Draft

Prevention of Significant Deterioration Application for Replacement of Co-Generation Plant

Prepared for

Rio Tinto Minerals – U.S. Borax Boron Operations

Submitted to

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CH2MHILL®

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Acronyms and Abbreviations

°F	degrees Fahrenheit
AB	Assembly Bill
AB32	Assembly Bill 32
AECOM	AECOM Environmental
AR	argon
BACT	Best Available Control Technology
Btu	British thermal unit(s)
Btu/scf	British thermal units per standard cubic foot
CARB	California Air Resources Board
CCS	Carbon Capture and Storage
CEC	California Energy Commission
CEQA	California Environmental Quality Act of 1970
CFR	Code of Federal Regulations
CH_4	methane
CHP	combined heat and power
Clean Energy	Clean Energy California
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
co-gen	cogeneration
Co-gen Project	U.S. Borax Boron Cogeneration Replacement Project
CPUC	California Public Utilities Commission
CTG	combustion turbine generator
DB	duct burning
DLN	dry low NOx
DOE	U.S. Department of Energy
EKAPCD	Eastern Kern Air Pollution Control District
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPA Region 9	U.S. Environmental Protection Agency Region 9
EPS	emissions performance standard
GE	General Electric
GHG	greenhouse gas
GHG Tailoring Rule	Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule
gr	grain
gr/scf	grain per standard cubic foot
GWh	gigawatt hour
H_2O	water
HAP	hazardous air pollutant
HFC	hydrofluorocarbon
HHV	higher heating value
HRSG	heat recovery steam generator
IPCC	Intergovernmental Panel on Climate Change

kW	kilowatt
KWH	kilowatt hour
LAER	Lowest Achievable Emission Rate
Lb(s)/hr	pound(s) per hour
Lb(s)/MMBtu	pound(s) per million British thermal units
lb/MW	pound per megawatt
lb/scf	pounds per standard cubic foot
LHV	lower heating value
LNG	Liquefied natural gas
Mandatory Reporting Rule	EPA Final Mandatory Reporting of Greenhouse Gases Rule
MMBtu	million British thermal units
MMBtu/hr	million British thermal units per hour
MW	megawatt(s)
MWh	megawatt hour
N_2	nitrogen
N_2O	nitrous oxide
NA	not applicable
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NGCC	natural gas combined cycle
NOx	nitrogen oxides
NSR	New Source Review
NSPS	New Source Performance Standards
O_2	oxygen
PE	Powers Engineers
PFC	perfluorocarbon
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 micrometers in aerodynamic diameter
PM_{10}	particulate matter less than 10 micrometers in aerodynamic diameter
PSA	pressure swing adsorption
PSD	Prevention of Significant Deterioration
Psig	pounds per square inch, gauge
PTE	potential to emit
PUC	Public Utilities Commission
RACT	Retrofit Available Control Technology
RPS	Renewable Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SO_2	sulfur dioxide
SOx	sulfur oxides
TBtu	Trillion British thermal units
tpy	tons per year
USFWS	U.S. Fish and Wildlife Service
VOC	volatile organic compound

SECTION 1

Project Summary

U.S. Borax Inc. (U.S. Borax) is proposing to replace the existing cogeneration (co-gen) plant at its facility in Boron, California. The replacement co-gen plant will consist of two natural-gas-fired combustion turbine generators with auxiliary fired heat recovery steam generators (HRSG) to produce up to 500,000 pounds per hour (lbs/hr) of process steam and approximately 76 megawatts (MW) of electricity. The new equipment will replace the existing U.S. Borax Westinghouse W251 generator and HRSG equipment (Co-Generation Facility I, Permit Number 10004077L). Once the new turbines and HRSG units are operational, the existing co-gen plant will be decommissioned. Installation of the new equipment and the decommissioning of the existing equipment together are referred to in this application as the U.S. Borax Boron Cogeneration Replacement Project (Co-gen Project). All other emission units at the U.S. Borax facility will remain the same, including vehicle operations. The boilers will remain in place and be used when one or both co-gen units are not operating as required to meet steam demand.

As with the current co-gen plant, the replacement co-gen plant will provide electricity to the U.S. Borax refinery, as well as additional electricity to the nearby Clean Energy California LNG Plant (Clean Energy). The combined power demands of the U.S. Borax refinery and Clean Energy are estimated to range from 20 to 28 MW, with the remainder of the electricity produced by the system going to Southern California Edison (SCE) under a power purchase agreement. The Clean Energy facility will supply blended return gas that U.S. Borax will use to augment pipeline-supplied natural gas as fuel for the Co-gen Project.

The Co-gen Project will not result in emission increases of any criteria pollutants above the Prevention of Significant Deterioration (PSD) significance thresholds, so PSD permitting is not required for those pollutants. However, conservative potential to emit calculations indicate that the Co-gen Project will result in a greenhouse gas (GHG) emissions increase above the PSD significance threshold for GHGs. This application, therefore, addresses the GHG emissions resulting from the Co-gen Project and includes a Best Available Control Technology (BACT) analysis for GHGs.

While emissions calculations indicate that, for PSD purposes, GHG emissions for the Co-gen Project will require a PSD permit, these calculations were conservative using potential to emit (PTE) assumptions for the new equipment as specified in the PSD regulations. More significantly, the calculation did not include the GHG reductions attributable to U.S. Borax's production of all of its industrial process steam using new, more-efficient combustion turbines. Historically the U.S. Borax facility has produced some of its own process steam from the existing co-gen plant, but has also relied on purchasing significant quantities of additional industrial process steam from the nearby Lakeshore Mojave generating station to provide all of the industrial process steam necessary for the U.S. Borax operation. The replacement co-gen plant will eliminate U.S. Borax's purchases of industrial process steam from the Lakeshore Mojave generating station.

As a result of the Co-gen Project, U.S. Borax will produce all of its own industrial process steam using new, more efficient General Electric (GE) LM 6000 PC combustion turbines, thus reducing overall GHG emissions attributable to electricity and steam production for the U.S. Borax facility. From a GHG emissions perspective, the Lakeshore Mojave combustion turbines used to produce the steam that U.S. Borax historically relied on are older and less efficient, especially compared to the new turbines U.S. Borax will use in the Co-gen Project. Although U.S. Borax cannot take formal PSD credit for the GHG reduction attributable to changing from steam purchased from the Lakeshore Mojave facility to production of its own industrial process steam, this change will result in an overall reduction of actual GHG emissions attributable to the electricity and steam needs of the U.S. Borax operation. Thus, the calculated summary of GHG emission increases used to determine that the Co-gen Project required a GHG PSD permit were not only conservative using PTE assumptions, but did not include the GHG reductions attributable to U.S. Borax's production of all of its industrial process steam using new, more-efficient combustion turbines. U.S. Borax believes that had such a calculation been done, overall GHG emissions per pound of steam produced for the U.S. Borax operation would be lower than the current emission levels that include the steam purchased from Lakeshore Mojave generating station.

Additionally the Co-gen Project will allow U.S. Borax to supply excess electricity to SCE, thereby reducing SCE's need to purchase electricity from older, less-efficient combustion turbines, which results in GHG emission reductions for the electricity produced. Not only will GHG emissions be reduced, but the turbine design selected by U.S. Borax allows quick turndown to meet SCE's flexibility requirements with respect to the management of other, less-reliable, renewable resources that supply the grid. In addition, the Co-gen Project will further California's energy conservation goal of increasing power production from cogeneration. These aspects of the Co-gen Project will result in further reductions in GHG emissions.

Modification of the existing facility and installation of the replacement Co-gen Project requires two separate approvals before changes are made onsite. The Eastern Kern Air Pollution Control District (EKAPCD) is the local regulatory authority for criteria pollutants and requires the submittal of an Authority to Construct permit application. EKAPCD currently does not have the authority to issue permits for major sources of criteria pollutants and major source GHG emission increases and major modifications under 40 CFR § 52.21 – Prevention of Significant Deterioration. The U.S. Environmental Protection Agency Region 9 (EPA Region 9) currently has this authority. The application package required by EKAPCD is being submitted concurrently and is attached as Appendix A to this application.

SECTION 2

Applicant Information

Applicant: U. S. Borax, Inc.

Location: 14486 Borax Road
Boron, California 93516-2000

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SECTION 3

Project Location

The replacement co-gen units will be located near the existing units at the U.S. Borax facility located north of Highway 58, at 14486 Borax Road, near the town of Boron, California. The area is rural, with few residences or commercial areas within a 2-mile radius of the facility. This location is within the boundaries of the EKAPCD. A site location map is shown in Figure 3-1.

The plant is located approximately 155 kilometers from the nearest Class I area, Joshua Tree National Park.

US Borax, Site Location

FIGURE 3-1
Site Location Map
U.S. Borax Replacement Co-Generation Plant
Boron, California

SECTION 4

Project Description

The replacement co-gen system will consist of the two turbines, each with an HRSG, equipped with supplemental duct burners. A diagram of the plant layout and major equipment components is shown in Figure 4-1. A plant configuration diagram is shown in Figure 4-2. The turbines and duct burners will be fueled with pipeline quality natural gas. The duct burners provide additional heat that enables the HRSGs to produce more steam to meet refinery steam demand. At full load, each turbine will generate approximately 38 MW electricity at average ambient conditions. Heat from the turbine exhaust will be used in the HRSGs to generate steam. With the turbines operating at full load and the duct burners in-service, each of the HRSGs will produce up to 250,000 lbs/hr steam for refinery needs, which results in an overall plant output of approximately 76 MW electricity and 500,000 lbs/hr steam.

As discussed in Section 1, the Co-gen Project will produce electricity that will be used by both the U.S. Borax refinery operations and Clean Energy. The U.S. Borax Boron Operations and Clean Energy power demands are estimated to range from 20 to 28 MW, with the remainder of the electricity produced by the turbines going to SCE under a power purchase agreement. If SCE needs less power than the turbines produce, U.S. Borax will have to adjust operations of the co-gen plant, which may result in turbine turndowns or one turbine being shut down. This might, in turn, require that U.S. Borax use duct burning on one or both HRSGs, and/or operate the existing boiler(s) to ensure adequate steam production for refinery operation.

The plant is designed to allow flexibility in producing both power and steam as required; as such it will have the ability to operate in various modes to match refinery operating conditions and external power demand. The refinery's steam demand can change quickly depending on short-term production requirements or variations in ore quality. The co-gen system could be operated with one or two turbines, with and without duct burning, and in an electrical production mode providing no steam to the facility, with examples provided below:

- Operation of Turbines, HRSGs, and Duct Burners. Both turbines and HRSGs are in full operation with use of the auxiliary duct burners operating at a rate needed to match steam demand to meet refinery operating requirements. When operating with this configuration, up to 500,000 lbs/hr steam and 76 MW of electricity can be produced.
- Operation of Turbines and HRSGs, but not Duct Burners. When refinery steam demand is low and both turbines and HRSGs are operating, it may not be necessary to operate the auxiliary duct burners. The auxiliary duct burners are used when the refinery's steam demand increases above the amount that can be produced by either one or both turbines and the HRSG(s) alone
- Operation of One Turbine and HRSG with Duct Burner. Operation of one turbine and HRSG with duct firing during periods of planned or unplanned maintenance to the other turbine would be necessary if refinery steam demand during the planned or unplanned maintenance period called for more steam than the one turbine and HRSG could produce. The level of duct burner operation would depend on the refinery steam demands.
- Reduced Refinery Steam Demand. Changes in refinery operations resulting in a sudden drop in steam demand, such as equipment malfunction, might result in not needing to operate the auxiliary duct burners and limited operation of the turbines, and/or little or no operation of the HRSGs.
- SCE Electricity Demand. SCE electricity demand might be low enough that U.S. Borax would decide to operate only one turbine. This might require U.S. Borax to use duct firing on the operating turbine and HRSG, or operate an existing boiler to ensure adequate steam production for refinery operation.
- Electricity Demand when No Steam Demand from Refinery. The need to provide electrical power to SCE to match rapidly changing power demands because of renewable energy production variability (for example, when the wind stops blowing or clouds obscure the sun), especially during periods when the refinery is down

for maintenance or operational purposes, could result in operation of the turbines only. HRSGs or the duct burners may not be needed because no steam would be required for refinery operations.

While the foregoing is a summary of some possible operating modes for the co-gen system, the two-turbine system with HRSGs equipped with auxiliary duct burners is designed for ultimate flexibility to adjust to changing refinery steam and electricity demands, as well as SCE electricity needs.

The co-gen plant requires the flexibility to burn pipeline natural gas as well as blended return gas received from Clean Energy. The return gas from Clean Energy must meet a pipeline quality natural gas specification which includes a minimum specification of 90.5 percent methane (CH_4). Actual CH_4 content of the LNG varies between 90.5 percent to nearly 100 percent (affecting heat value of the fuel) and can change quickly. The GE LM 6000 PC turbines are able to handle this rapidly varying heat value from the fuel, as well as variable load demand, more efficiently than other turbines.

Construction of the proposed co-gen facility would occur over a 12-month period and would employ a peak workforce of 48.

The co-gen plant will be operated up to 7 days per week, 24 hours per day. When the plant is not operating, personnel will be present as necessary for maintenance, to prepare the plant for startup, and/or for site security.

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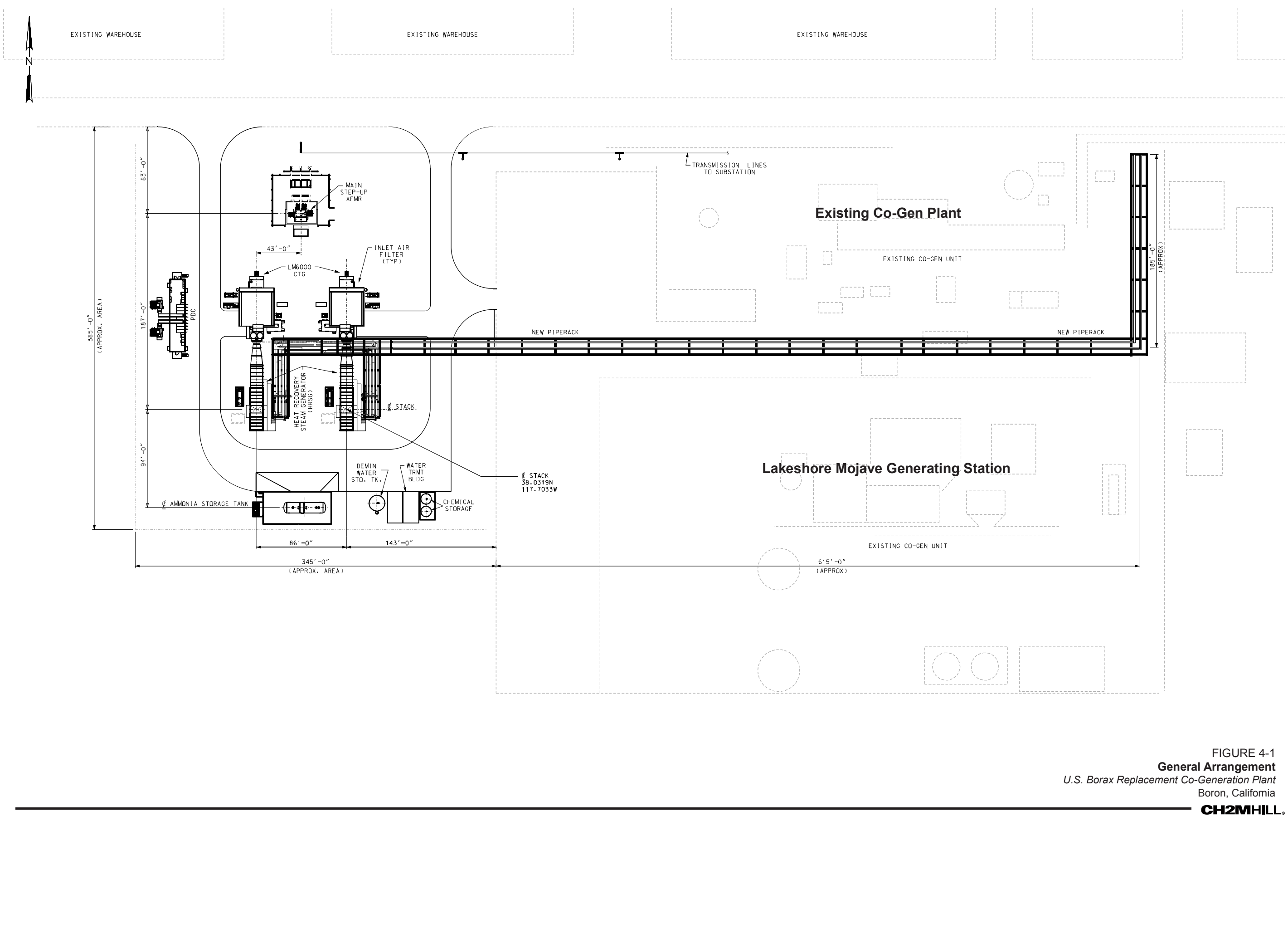

FIGURE 4-1
General Arrangement
U.S. Borax Replacement Co-Generation Plant
Boron, California

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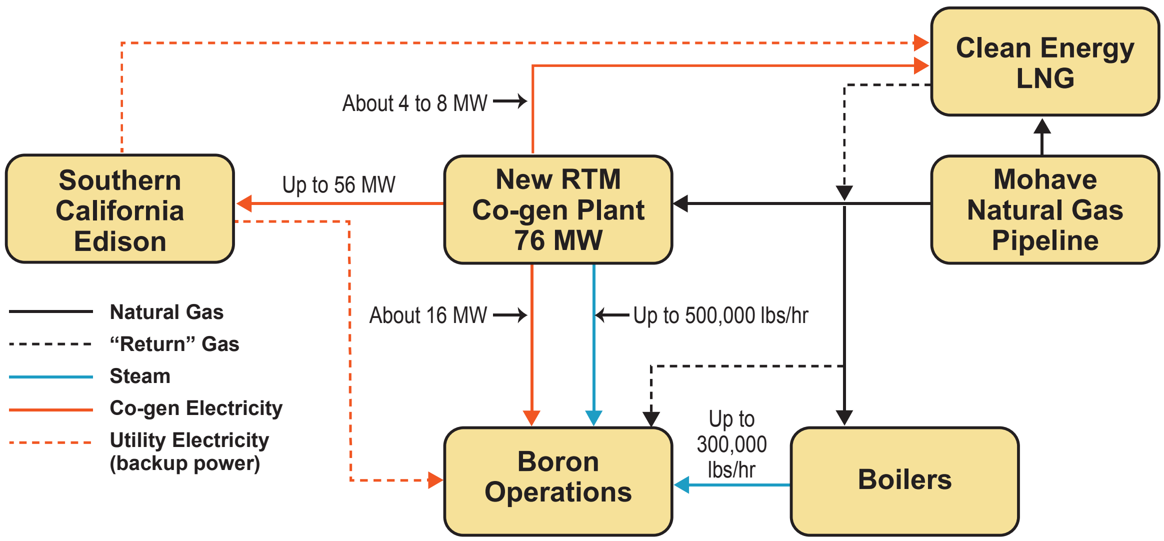

FIGURE 4-2
Proposed Co-Gen Energy Configuration
U.S. Borax Replacement Co-Generation Plant
Boron, California

SECTION 5

Project Emissions

5.1 Summary of Emission Increases from the Co-gen Project

The PTE from the replacement co-gen equipment and the past actual emissions from the existing co-gen equipment for each criteria pollutant are compared in Table 5-1. The Co-gen Project shows a de minimis increase in emissions for volatile organic compounds (VOCs), sulfur dioxide (SO_2), and particulate matter (PM), including PM_{10} (particulate matter less than 10 micrometers in aerodynamic diameter) and $PM_{2.5}$ (particulate matter less than 2.5 micrometers in aerodynamic diameter). Combustion sources emit $PM_{2.5}$ and therefore PM_{10} and $PM_{2.5}$ are assumed to be equal. Although VOC, SO_2, and PM_{10}/$PM_{2.5}$ emissions have increased, the emissions increase is below the PSD significance thresholds as outlined in 40 CFR 52.21. Nitrogen oxides (NO_x) and carbon monoxide (CO) emissions show a decrease. Therefore, only GHG emissions require a PSD permit and BACT review.

TABLE 5-1
Project Emissions Summary

Pollutant	2 CTGs with DB PTE TPY	24 Month Past Actual[1] TPY	Difference (PTE - Past Actual) TPY	PSD Significance Thresholds TPY
NO_x	34.0	128	-94.3	40
CO	19.6	133	-112.9	100
VOC	5.6	4.5	1.1	40
SO_2	12.4	1.27	11.2	40
PM_{10}	20.6	10.7	9.9	15
$PM_{2.5}$	20.6	10.7	9.9	10
GHG (CO_2e)	552,925	261,066	291,859	75,000

[1] Past actual for existing co-gen facility
CO = carbon monoxide
CTG = combustion turbine generator
DB = duct burning
NO_x = nitrogen oxides
$PM_{2.5}$ = particulate matter less than 2.5 micrometers in aerodynamic diameter
PM_{10} = particulate matter less than 10 micrometers in aerodynamic diameter
PTE = potential to emit
SO_2 = sulfur dioxide
TPY = tons per year
VOC = volatile organic compound
GHG = Greenhouse Gases
CO_2e = carbon dioxide equivalents (carbon dioxide (CO_2) methane (CH_4), and nitrous oxide (N_2O))

5.2 Calculation of Potential to Emit of New Co-gen Equipment

The expected emissions from the two CTGs and HRSGs were calculated using EPA Reference Method 19. The values used in these calculations are provided in Appendix B. PTE calculations were assessed for steady state operations and startup/shutdown of the CTGs and HRSGs. Emissions by pollutant, with and without duct firing, are available in Appendix B. A summary of all PTE calculations for the proposed project are in Appendix B. The total heat input for both turbines and duct-fired HRSG units used in these emissions calculations is limited to 9.15 trillion Btu (TBtu) per 12-month period.

Several performance cases were evaluated to determine the maximum potential heat input required to produce maximum load from each turbine and HRSG unit with duct firing. Lower temperatures and increased humidity increase the density of the air drawn into the turbine and increase the heat input needed to produce the same amount of energy. Higher ambient temperatures lower the amount of energy to produce steam in the HRSGs and lower the heat input from the duct burners. Therefore, a range of temperature and humidity conditions that have occurred in the region where U.S. Borax is located were evaluated. These configurations are summarized in Appendix B.

Based on the total heat input using the high heat value, the highest heat input occurs when ambient temperatures are 20 degrees Fahrenheit (°F) and relative humidity is 75 percent (See Appendix B). Because these meteorological conditions will not occur throughout the year, using the total heat input for this scenario is conservative and reflects a maximum PTE.

5.2.1 Criteria Pollutant Emissions

Using the conditions described above and the emission rates determined through the BACT evaluation in the EKAPCD permit application (see Appendix A), the emission rates for the criteria pollutants are presented in Table 5-2.

TABLE 5-2
Criteria Pollutant Emission Rates and Limits without and with Duct Burning

	Emission Limit per CTG (no duct burning)	Emission Limit per CTG (with duct burning)
NO_x	• 3.2 lb/hr • 1-hr average • 2.0 ppmv @15% O_2	• 4.1 lb/hr • 3-hr average • 2.0 ppmv @15% O_2
CO	• 1.9 lb/hr • 1-hr average • 2.0 ppmv @15% O_2	• 2.3 lb/hr • 3-hr average • 2.0 ppmv @15% O_2
VOC	• 0.5 lb/hr • 1-hr average • 1.0 ppmv @15% O_2	• 1.2 lb/hr • 3-hr average • 2.0 ppmv @15% O_2
SO_2	• 1.2 lb/hr • 1-hr average • 0.00272 lb/MMBtu (assuming 1 gr/100 scf and 1,050 Btu/scf)	• 1.5 lb/hr • 1-hr average • 0.00272 lb/MMBtu (assuming 1 gr/100 scf and 1050 Btu/scf)
PM_{10}	• 2.2 lb/hr • 1-hr average	• 2.5 lb/hr • 1-hr average
$PM_{2.5}$	• 2.2 lb/hr • 1-hr average	• 2.5 lb/hr • 1-hr average

Btu/scf = British thermal units per standard cubic foot
CO2e = carbon dioxide equivalent
lb/MMBtu = pound(s) per million British thermal units
O2 = oxygen
gr =grain
gr/scf = grain per standard cubic foot
hr = hour
ppmv = parts per million volume

5.2.2 Greenhouse Gas Emissions

Detailed GHG emission calculations are set forth in Appendix B, with summaries provided below. All GHG emissions are converted to tpy of CO_2e and totaled in Table B-5 (Appendix B). GHG emissions are dominated by CO_2 emissions from natural gas combustion. The combustion turbines and duct burners will be fired with a blend of pipeline-supplied natural gas and blended return gas from Clean Energy. The fuel will meet California pipeline natural gas specifications. The complete combustion of the gas will result in the production of water and CO_2 byproducts. However, the incomplete combustion process will also result in the release of unburned gas resulting in the emissions of CH_4. Additionally, due to the presence of nitrogen in the combustion air, some small quantities of nitrous oxide (N_2O) will also be emitted. The GHG emissions summarized above and detailed in Appendix B are converted to a CO_2 equivalent (CO_2e), assuming a CO_2e global warming potential factor for CH_4 and N_2O of 21, and 310, respectively. These factors are from the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report 1995. The CO_2 emission rate assumes the rate for natural gas with a heat value greater than 1,100 Btu/scf to reflect the combustion of LNG. The annual potential to emit emission estimate is based on a heat input 9.15 TBtu per 12-month period.

PTE emissions are summarized in Tables 5-3 through 5-5.

TABLE 5-3
PTE Emission Summary for Turbines with Duct Burner Steady Operations

	One CTG Plus Duct Burner			Two CTG Plus Duct Burner	
Emissions	lb/hr	lb/12-Month Period	Tons/12-Month Period	lb/hr	Tons/12-Month Period
NO_x	4.1	33,607	16.8	8.2	33.6
CO	2.3	19,271	9.6	4.6	19.2
VOC	1.2	5,626	2.8	2.4	5.6
SO_2	1.5	12,434	6.2	3.0	12.4
PM_{10}	2.5	20,572	10.3	5.0	20.6
$PM_{2.5}$	2.5	20,572	10.3	5.0	20.6
CO_2e				115 lb/MMBtu 365-day rolling average	552,925

5.2.3 Startup and Shutdown Emissions

The annual emission estimates assume 12 startups and shutdowns over a 12-month period per turbine. These are estimates based on anticipated reliability of the turbines and U.S. Borax refinery needs. Startup and shutdown emissions are higher for NO_x, CO, and VOCs because the emissions of these pollutants are reduced by catalytic control systems, which need time to reach optimum operating temperatures. The other criteria pollutant emissions and GHG emissions would not be affected by startups and shutdowns. The startup and shutdown emissions for NO_x, CO, and VOCs are presented in Table 5-4. Because startup and shutdowns are short in duration for the LM 6000 PC turbines, the impact on the annual emissions estimates from startup and shutdown events is negligible. These emissions have nevertheless been calculated and added to the overall emission estimates, but the annual emissions estimates would not be significantly impacted if more startups or shutdowns were to occur than the number on which these estimates was based. The assumptions regarding startup and shutdown durations and additional details on the calculations of emissions from startup and shutdown events are in Appendix B.

TABLE 5-4
Startup/Shutdown PTE for 2 CTG with 12 Events/Year

Pollutant	Startup lb/Event	Shutdown lb/Event	Startup lb/12-Month Period	Shutdown lb/12-Month Period	Start/Stop Tons/12-Month Period
NO_x	25.7	6.4	308.8	76.3	0.19
CO	25.7	5.3	308.2	64.1	0.19
VOC	1.1	0.4	13.0	4.6	0.009

5.2.4 Summary of PTE Emissions from Replacement Co-gen Equipment

Adding the steady state emissions to the startup and shutdown emissions (Tables 5-3 and 5-4), the total PTE from both units, assuming a total heat input of 9.15 TBtu per 12-month period, was calculated. These emissions are presented in Table 5-5.

TABLE 5-5
Summary of PTE per 12-Month Period

	1 CTG with DB				2 CTG with DB
Pollutant	Steady Operation (lb)	Starts/stops (lb)	Total (lb)	TPY	TPY
NO_x	33,607	385	33991.8	17.00	34.0
CO	19,271	372	19643.5	9.82	19.6
VOC	5,626	18	5644.0	2.82	5.6
SO_2	12,434	14	12447.2	6.22	12.4
PM_{10}	20,572	21	20592.9	10.30	20.6
$PM_{2.5}$	20,572	21	20592.9	10.30	20.6
CO_2e	NA	NA	NA	NA	552,925

NA = Not Applicable

5.3 24-Month Average of Past Actual Emissions

Past actual emissions for the existing co-gen equipment were calculated in accordance with 40 CFR 52.21 (b)(48)(ii), which states:

> *For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Administrator for a permit required under this section or by the reviewing authority for a permit required by a plan, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.*

In addition, 40 CFR 52.21(b)(48)(ii)(d) allows a different consecutive 24-month period to be used for each regulated New Source Review (NSR) pollutant. The past actual emissions for the criteria pollutants were based on the operations of the current turbine and duct burner. The GHG emissions were calculated using the heat input into the turbine and duct burner and The Climate Registry General Reporting Protocol. Detailed calculations are presented in Appendix B. The past actual emissions in tpy for each of the criteria pollutants and GHG emissions in CO_2e tpy, with the corresponding time frame used for the averaging, are presented in Table 5-6.

TABLE 5-6
Past Actual Emissions Summary

	NO_x	CO	VOC	$PM_{10}/PM_{2.5}$	SO_2	CO_2e
Maximum Emissions for Consecutive 24 Months (tpy)	128	133	4.5	10.7	1.27	261,066
Timeframe	April 2007 through March 2009	August 2009 through July 2011	April 2007 through March 2009	August 2009 through July 2011	April 2007 through March 2009	April 2007 through March 2009

SECTION 6

Best Available Control Technology

6.1 Introduction

This BACT evaluation was prepared to address GHG emissions from the Co-gen Project. This BACT evaluation follows EPA regulations and guidance for BACT analyses, as well as the *EPA's PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA, 2011b). GHG pollutants are emitted during the combustion process when fossil fuels are burned. One of the possible ways to reduce GHG emissions from fossil fuel combustion is to use inherently lower GHG-emitting fuels and to minimize the use of fuel, which is achieved by using a thermally efficient process for the CTGs, as well as by using a co-gen process that ensures that excess heat from the turbines is used to produce required process steam. In this process, the fossil fuels burned are natural gas and LNG, which are the lowest GHG-emitting fossil fuels available. The gas turbines selected to meet the project objectives have a high thermal efficiency.

6.1.1 Regulatory Overview

In 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA determined that six GHG pollutants (collectively combined and measured as CO_2e) were NSR-regulated pollutants and therefore subject to PSD permitting when new projects emitted those pollutants above certain threshold levels. Under the GHG Tailoring Rule, beginning July 1, 2011, new sources with a GHG PTE equal to or greater than 100,000 tpy of CO_2e will be considered a major source and required to undergo PSD permitting, including preparation of a BACT analysis for GHG emissions. Modifications to existing major sources (CO_2e PTE of 100,000 tpy or greater) that result in an increase of CO_2e greater than 75,000 tpy are similarly required to obtain a PSD permit, which includes a GHG BACT analysis. The Co-gen Project results in an emissions increase above both the new source and modification PSD thresholds for CO_2e. Therefore, the Co-Gen Project is subject to the GHG Tailoring Rule, and is required to obtain a PSD permit for GHGs.

6.1.2 BACT Evaluation Overview

BACT requirements are intended to ensure that a proposed project will incorporate control systems that reflect the latest control technologies that have been demonstrated in practice for the type of facility under review. BACT is defined under the Clean Air Act (42 U.S.C. § 7479[3]) as follows:

> *The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. BACT is defined as the emission control means an emission limitation (including opacity limits) based on the maximum degree of reduction which is achievable for each pollutant, taking into account energy, environmental, and economic impacts, and other costs. ….*

EPA guidance specifies that a BACT analysis should be performed using a top-down approach in which all applicable control technologies are evaluated based on their effectiveness and then ranked by decreasing level of control. If the most-effective control technology is not being selected for the project, the control technologies on the list are evaluated as to whether they are infeasible because of energy, environmental, and/or economic impacts. The most effective control technology in the ranked list that cannot be so eliminated is then defined as BACT for that pollutant and process. A further analysis must be conducted to establish the emission limit that is BACT, based on determining the lowest emission limit that is expected to be consistently achievable over the life of the plant, taking into account site-specific and project-specific requirements.

The steps required for a "top-down" BACT review are the following:

1. Identify available control technologies
2. Eliminate technically infeasible options
3. Rank remaining technologies
4. Evaluate remaining technologies (in terms of economic, energy, and environmental impacts)
5. Select BACT (the most-effective control technology and lowest consistently achievable emission limit) that has not been eliminated for economic, energy, or environmental impact reasons

For a facility subject to the GHG Tailoring Rule, the six covered GHG pollutants are:

- CO_2
- N_2O
- CH_4
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur hexafluoride (SF_6)

Although the top-down BACT analysis is applied to GHGs, there are "unique" issues in the analysis for GHG that do not arise in BACT for criteria pollutants (EPA, 2011b). For example, EPA recognizes that the range of potentially available control options for BACT Step 1 is currently limited and emphasizes the importance of energy efficiency in BACT reviews. *Id.* at 33, 21. Specifically, EPA states that:

> *The application of methods, systems, or techniques to increase energy efficiency is a key GHG-reducing opportunity that falls under the category of "lower-polluting processes/practices." Use of inherently lower-emitting technologies, including energy efficiency measures, represents an opportunity for GHG reductions in these BACT reviews. In some cases, a more energy efficient process or project design maybe used effectively alone; whereas in other cases, an energy efficient measure may be used effectively in tandem with end-of-stack controls to achieve additional control of criteria pollutants.*

Id. at 29. Based on this reasoning, EPA provides permitting authorities with the discretion to use energy-efficient measures as "the foundation for a BACT analysis for GHGs . . ." *Id*. One of these measures is the use of both the thermal energy and the electricity that is generated on-site, *id.* at 30, which is a hallmark of cogeneration.

6.2 Project Specifics

6.2.1 Overview

As described in Section 1, U.S. Borax plans to replace its existing Westinghouse W251 generator and HRSG equipment (Co-Generation Facility I, Permit Number 10004077L) with more-efficient GE LM6000 PC natural gas-fired CTGs with HRSGs with auxiliary duct burners.

The main purpose of the replacement co-gen facility is to provide steam and power to the U.S. Borax refinery. Another purpose is to supply power to Clean Energy as well as to the power grid. Process steam is necessary to heat intermediate product and avoid premature crystallization in the borate production process. The facility cannot operate without the steam. Currently, U.S. Borax augments the steam produced from its existing co-gen unit with steam purchased from the nearby Lakeshore Mojave generating station. The replacement co-gen plant will allow U.S. Borax to operate independently from Lakeshore Mojave and produce steam and power using newer, more-efficient equipment. In addition to producing power and steam for the borate process, U.S. Borax will provide power to the grid.. The U.S. Borax plant provides power to the grid when solar or wind power is not available. Due to the fluctuating demands of steam from the U.S. Borax refinery and power to the grid, the replacement co-gen units must be designed to provide quick turnup and turndown of both power and steam.

6.2.2 Unique Operational Considerations of the U.S. Borax Co-gen Project

6.2.2.1. The Turbine Selected for the Co-gen Project Cannot be Directly Compared to Power Plant Turbines

In contrast to CTGs used in a power plant where all energy is used to produce electricity and the turbine selection can be based solely on thermal efficiency, a co-gen facility uses energy to produce both steam and electricity. As discussed above in the Project Description, a key aspect of the U.S. Borax co-gen system is its ability to adapt to quickly changing refinery steam demands and SCE reductions in electricity demands. The duct burners produce energy, but the energy is used to augment steam production for the U.S. Borax refinery needs. This essential difference between the U.S. Borax co-gen system and a power plant means that the turbine selection for the Co-gen Project includes factors beyond simple thermal efficiency as measured in pounds of CO_2 per megawatt hour (MWh). As a result, the co-gen system turbines with duct burners cannot be directly compared to turbines used solely for electricity production. Yet, the fact that the system at U.S. Borax is a co-gen system already achieves energy efficiency because of the very nature of the co-gen process.

6.2.2.2. Cogeneration is a Preferred Method for Reducing GHGs

The system at U.S. Borax is a co-gen system. Co-gen is already a preferred method for producing power from an energy efficiency perspective, because of the very nature of the co-gen process. For example, the thermal electric generation processes lose 50 to 70 percent of the input fuel energy in the form of waste heat. Recovering this energy for steam or hot water production onsite or at a nearby facility increases the overall efficiency of the process from 30 to 50 percent to 70 to 80 percent (EPA, 2010). This reduction in fuel requirements translates directly to reduced GHG emissions per unit of energy on a lb/ Btu input basis. The State of California has recognized the importance of cogeneration systems in achieving GHG reductions, as discussed below.

The California legislature enacted Public Resources Code Section 25004.2, which provides in pertinent part as follows:

> *….cogeneration technology…should be an important element in the State's energy supply mix…can assist meeting the state's energy needs while reducing the long-term use of conventional fuels…reduces negative environmental impacts…and that cogeneration should receive immediate support and commitment from state government.* (CEC, 2010)

The CEC issued Order No. 08-1217-16 on December 18, 2008 instituting a rulemaking proceeding to implement the Waste Heat and Carbon Emissions Reduction act, codified in Sections 2840 through 2845 of the Public Utilities Code. This rulemaking is consistent with and furthers the legislature's emphasis on encouraging development of cogeneration projects.

The California Air Resources Board (CARB) is relying on the co-gen process to help *reduce* GHG emissions over the next 10 years. CARB has approved a Scoping Plan and a Supplement that set forth the strategies recommended to achieve the GHG reduction targets included in California Assembly Bill 32(AB32), Global Warming Solutions Act of 2006. The expansion of co-gen capacity is a critical component of CARB's strategy. CARB emphasizes that cogeneration "can reduce GHG emissions by displacing emissions from power plants . . . [and] often improve grid reliability, reduces dependence on transmission lines, and reduces electrical transmission and distribution energy loss" (CARB, 2011).

CARB recommends the installation of approximately 4,000 MW of new co-gen capacity to ensure that emissions of GHGs in California are at 1990 levels by 2020 (CARB, 2008). Consistent with this target, the California Energy Commission (CEC) has proposed a number of recommendations designed to reduce market and regulatory barriers to co-gen; one of these regulations is the adoption of GHG regulations that "fully reflect the benefits of combined heat and power . . ." (CEC, 2007). *Id*. In addition, the California Public Utilities Commission (CPUC) has agreed to develop a combined heat and power (CHP) Program designed to encourage the development of cogeneration. *See* CHP Program Settlement Agreement Term Sheet (CPUC, 2010).

6.2.2.3. The Project Objectives for the Co-gen Project Were Unique and Drove the Turbine Selection Process

In addition, the U.S. Borax co-gen system has multiple project objectives and requirements, which the CTG selected for the project needs to meet. As the following discussion demonstrates, the turbines selected for the Co-gen Project, the GE LM 6000 PCs, were the only turbines of the five models evaluated that met all of the project objectives. Because the turbine selection process was necessary to ensure that the project can meet the project objectives and these objectives are an intrinsic part of the U.S. Borax operations and the very design of the co-gen system, the turbine selection is inherent to the project design.

As EPA guidance and Environmental Appeals Board precedent emphasize, BACT requirements are not a means of redefining the design of the source. NSR Manual at B.13; *In re Northern Michigan University*, PSD Appeal No. 08-02 (2009), slip op. at 26. The design of the source is the "proposed facility's end, object, aim, or purpose" as defined by the project applicant. *In re Desert Rock Energy Co., LLC*, PSD Appeal No. 08-03 (Environmental Appeals Board, Sept. 24, 2009), slip op. at 64 (citations omitted). In EPA's PSD and Title V guidance for permitting GHG, EPA indicates that the BACT analysis should not generally "be applied to regulate the applicant's purpose or objective for the proposed facility" (EPA, 2011). Specifically, if an available control technology or design process is inconsistent with "'inherent' design elements" or the "fundamental purpose" of the proposed facility, then it need not be considered in the BACT analysis. *In re Northern Michigan University*, slip op. at 26.

As set forth in the Project Objectives below (Section 6.2.3), the fundamental purpose of the Co-gen Project is to accommodate U.S. Borax's rapidly changing production demands for reliable steam and electricity in a configuration that can respond quickly to fuel heat content variation. As set forth in detail in Section 4 and Section 6.2.3, the Co-gen Project is designed to allow for flexibility to produce both power and steam in various operating modes in order to match refinery operating conditions and external power demand. For example, the configuration must be able to handle rapid changes in steam demand, from producing maximum steam to the refinery through operation of the turbines and duct burners, to sudden reductions in steam demand resulting from refinery equipment malfunctions or other unforeseen issues. Similarly, the design must be able to manage varying electricity demand from SCE that may change in a matter of minutes or hours. This flexibility is critical to U.S. Borax's objectives and is integral to the design of the project. Additionally, the Co-Gen Project's design requires the ability to burn blended return gas from Clean Energy, which requires CTGs that can accommodate variable fuel heat content. Therefore, the turbine selection process will be discussed in detail before the top-down BACT analysis in this section.

6.2.3 Project Objectives

During the development of the Co-gen Project, several issues were identified as key requirements or objectives. These issues have been further considered and expanded as the project has been further evaluated. The project objectives include:

1. Replace the 25 year-old U.S. Borax single turbine-based co-gen facility with a state-of-the-art turbine technology with increased steam production efficiency and reduced emissions, including GHG, per unit of energy generated.
2. Develop a co-gen project that will provide sufficient steam capacity to supply 100 percent of U.S. Borax's foreseeable operational needs, eliminating the need to purchase steam from other suppliers.
3. Develop a co-gen project with a high degree of reliability, a high degree of turndown (and continued reliability in the turndown mode), and the capability for significant duct burning to meet variable steam requirements. Reliable steam generation and the ability to rapidly adjust the amount of steam produced are critical to the operation of the U.S. Borax facility. The existing cogeneration facility accommodates the increase in steam demand through a combination of duct firing, adjusting turbine load, and using auxiliary boilers. Decreases in steam demand are accommodated by reducing turbine load and the use of a HRSG bypass exhaust stack. With the replacement co-gen system, the release of excess steam through a turbine exhaust bypass will no longer be an option because all of the exhaust gas will be required to pass through the add-on pollution control

equipment. As a result, further flexibility in the ability to turndown steam production is necessary with the new equipment.

4. The existing co-gen facility relies on blended return gas from Clean Energy for part of its fuel. The dry low NOx (DLN) combustors used in the existing equipment to reduce emissions have made it time- and manpower-intensive to accommodate and ensure steady state operation of the existing co-gen system, given the rapid variations in the fuel heat content of the blended return gas. Because the return gas from Clean Energy is a useful fuel product to the U.S. Borax co-gen system, and it would otherwise be flared if not sold to U.S. Borax (generating GHG and other emissions without any useful energy produced), a key project objective is ensuring the continued ability to accommodate the blended return gas. By contract, the Clean Energy blended return gas meets pipeline quality natural gas standards.
5. Continue to supply electricity to the U.S. Borax and Clean Energy operations of between 20 and 28 MW. Electricity in addition to these amounts will be sold to the power grid. The power sold to the grid, including U.S. Borax's ability to rapidly adjust the amount of power it provides, will allow the grid to better accommodate renewable sources of power (wind and solar) because these sources are inherently variable in the amount of power they can be relied on to produce.
6. Use of two turbines and significant duct burning capability will increase the flexibility in accommodating fluctuating steam and power demands both from the U.S. Borax facility and from SCE.

6.2.4 Combustion Turbine Selection Process

In 2010, U.S. Borax contracted with Power Engineers (PE) to conduct an engineering study (PE, 2010) to evaluate replacement of its existing co-gen plant with equipment that would produce steam and electricity more efficiently than its current system, and would be capable of producing 100 percent of the process steam needed for the U.S. Borax operations. This report is shown in Appendix C. As part of that evaluation, PE reviewed available turbine designs to select the best turbine for the replacement co-gen system; in addition, U.S. Borax further evaluated PE's review of turbines to make its final assessment of the best turbine model to achieve its project objectives (as described above).

PE evaluated the following turbine models for use in the U.S. Borax replacement co-gen plant:

- GE LM6000 PC (water-injected for NOx control)
- GE LM6000 PD/ GE LM6000 PF (DLN)
- Rolls Royce Trent 60D (DLN)
- Siemens SGT-800 (DLN)
- Solar Titan 250-T30000S (DLN)

These turbine models were selected for consideration because they met the initial project requirements of having an operating history of reliability in steam production, and they each had a 72-hour interchangeable engine core for improved reliability.

Table 6-1 presents summary information concerning the five turbine models evaluated in the PE report.

TABLE 6-1
Combustion Turbine Comparison for Power and Fuel [1]
Plant Performance Summary [2, 3, 4, 5] - Estimated

Plant Performance Variable	GE LM6000 PC	GE LM6000 PD	Rolls Royce Trent 60D	Siemens SGT-800	Solar Titan 250
Gas Turbine Gross Output, kW/Unit	39,003	38,076	46,543	42,267	19,568
Number of Gas Turbines	2	2	2	2	3
Combustor Type (NOx control)	Wet Injection	DLN	DLN	DLN	DLN
Total Gross Output, kW	78,006	76,152	93,085	84,533	58,705
Plant Auxiliary Losses, kW	1,378	1,258	1,529	1,448	1,196

TABLE 6-1
Combustion Turbine Comparison for Power and Fuel [1]
Plant Performance Summary [2, 3, 4, 5] ***- Estimated***

Plant Performance Variable	GE LM6000 PC	GE LM6000 PD	Rolls Royce Trent 60D	Siemens SGT-800	Solar Titan 250
Plant Net Output, kW	76,628	74,894	91,556	83,085	57,509
Net Plant Heat Rate, Btu/kWh (LHV)[6]	11,338	10,744	9,983	10,451	12,452
Gas Turbine Fuel Input/Unit, MMBtu/hr (HHV)	378.7	352.8	429.02	433.6	194.1
Duct Burner Fuel Input/Unit, MMBtu/hr (HHV)	55.2	49.0	27.4	0.0	44.3
Total Plant Fuel Input, MMBtu/hr (HHV)	867.7	803.6	912.8	867.2	715.2

[1] Reference: *Rio Tinto Minerals Boron Operations, New Cogeneration Facility Feasibility Study*. (PE, 2010)
[2] Ambient temperature of 59°F, relative humidity of 30%, site elevation of 2,400 feet, no inlet air cooling
[3] No gas compression (gas supply at 700 psig), natural gas fuel composition of 87% CH_4, 8.5% C_2H_6, 3.5% N_2
[4] Duct firing added to produce additional 175 kpph steam per turbine
[5] Saturated steam output at 150 psig, maximum 10°F superheat
[6] Values based upon simple cycle operations and not indicative of overall turbine efficiency.

MMBtu/hr = million British thermal units per hour
kW = kilowatt hour
HHV = higher heating value
LHV = lower heating value
psig = pounds per square inch, gauge
kpph =thousand pounds per hour

6.2.4.1. GE LM 6000 Models

The GE LM6000 PC uses water injection into the combustor section for NO_x control rather than DLN combustors, and accordingly, is less-sensitive than the PD and PF versions to variations in heat content.. The GE LM6000PD and the newer LM6000 PF1 (also a DLN engine) are not as well-suited as the LM6000 PC to burn fuel gas with varying heat input levels because of their DLN design. This was confirmed by the manufacturer. In addition, these DLN engines have limited turndown capability, with optimal performance and typically being guaranteed for NOx emissions compliance within the range from 65 to 100 percent load (PE, 2010). In contrast, the PC unit offers greater turndown, with its NO_x emissions performance typically being guaranteed down to 50 percent load and operating experience from 10 to 15 percent load. Because operating reliability at reduced load and using fuel with a variable heat content are key project objectives, the PC model is preferable to the PD and PF models.

Because of the need for reliable steam production, the reliability of each LM6000 model was researched as well. As of January 2011, approximately 1,000 LM6000 power generation packages collectively have been sold worldwide, which have accumulated more than 21.8 million operating hours (GE, 2011b). Based on the reliability data available, the GE LM6000 turbines have achieved a 98.8 percent documented gas turbine reliability and 97.7 percent gas turbine and generator set reliability (GE, 2011a). Of the approximately 1,000 LM6000 packages sold, approximately 748 have been the water-injected version of the GE LM6000 turbine and approximately 252 have been the DLN-based turbine. (GE, 2011b) At the time of the feasibility study, fewer than 30 GE LM6000 PF turbines had been sold worldwide (GE, 2011c). Therefore, because of the greater operational history with the LM 6000 PC turbines, the LM6000 PD and PF turbine were believed to be less desirable than the GE LM6000 PC turbines for meeting the reliability requirements of the project.

6.2.4.2. Rolls Royce Trent

The Rolls Royce Trent, like the LM6000 PD and LM6000 PF, uses the DLN combustor technology. As with the PD and PF versions, the Rolls Royce Trent DLN technology is not as well-suited to burn a mix of fuel gases with varying heat input levels. The manufacturer confirmed that the DLN technology would not be suitable for use with fuel of varying heat content. In addition, the Rolls Royce engine has a limited turndown capability (within the range of 65 to 100 percent load). Literature published by Rolls Royce since the 2010 study indicates a comparable water injected turbine, the RB211-GT61, may be commercially available in 2012. However, the RB211-GT61 was not evaluated because the performance data were not readily available and the 10 million-plus accumulated operating hours for the LM6000 PC at 98.8 percent documented gas turbine reliability and 97.7 percent gas turbine and generator set reliability (GE, 2011a) make the LM6000 PC turbine more desirable for meeting the reliability requirements for steam production.

6.2.4.3. Siemens SGT-800

The Siemens SGT-800 is a gas turbine comparable in size to the GE LM6000. Although the Siemens model was included in the study because it was considered to be the least sensitive to fuel supply variation of the DLN engine alternatives, it does not have duct burners. Therefore, the Siemens turbine would not be capable of accommodating rapid changes in steam demand, one of the key project objectives.

6.2.4.4. Solar Titan 250 – T3000S

The Solar Titan 250 – T3000S is a small turbine that uses DLN technology; the small size of the Solar Titan turbines means that three turbines would be required to produce the power and steam needed for the Co-gen Project. Despite their small size, these turbines have a higher net heat rate than the other turbines, so they would be less thermally efficient than the GE LM 6000 PCs. It may also be true that the Solar Titan 250 DLN burners, as with other DLN burners, would not be expected to be able to respond quickly to variable heat input from the fuel, a key project objective. However, because U.S. Borax was not able to get an affirmative response from the manufacturer, this could not be confirmed. Nevertheless, the Solar Titan 250 configuration can be ruled out as an appropriate turbine for the project because the Solar turbine configuration is less thermally efficient than the LM6000 PC configuration.

6.2.4.5.

As shown in Figure 6-1 and discussed above, of the five combustion turbines evaluated, only the GE LM6000 PC meets all of the project objectives. A configuration of two GE LM6000 PC gas turbine generators with HRSGs and duct burners was selected as the configuration for the Co-gen Project for the following reasons:

- The wet injection system for NOx control of the LM6000 PC (rather than the DLN technology used in the other turbines) allows the use of fuel with rapid changes in heat content, allowing the use of the blended return gas and pipeline-supplied natural gas.
- The LM6000 PC allows the use of a two turbine configuration with significant duct burning to accommodate fluctuations in steam demand and grid electricity demand.
- The LM 6000 PC operational experience and history provides a reliable method of achieving the rapid turndown required for both the facility's rapidly changing steam demand and sudden changes in electricity grid demand for power, due to generation from renewable power sources.
- Two GE LM6000 PCs combined with HRSGs with duct burners will be able to provide 500,000 pounds of steam while simultaneously providing electrical generation output of 76 MWs using new, more-efficient technology than the current co-generation system.

6.3 GHG BACT Analysis

6.3.1 Assumptions

During the completion of the GHG BACT analysis, the following assumptions were made:

1. Completion of the EKAPCD BACT analysis for criteria pollutants will result in the installation of a selective catalytic reduction (SCR) system for NO_x emissions reduction, and an oxidation catalyst for control of CO and VOCs for each turbine.
2. During actual combustion turbine operation, the oxidation catalyst may result in minimal increases in CO_2 from the oxidation of any CO and CH_4 in the flue gas. However, the EPA Final Mandatory Reporting of Greenhouse Gases Rule (Mandatory Reporting Rule) (40 CFR 98) factors for estimating CO_2e emissions from the combustion of natural gas assume complete combustion of the fuel. While the oxidation catalyst has the potential of incrementally increasing CO_2 emissions, these emissions are already accounted for in the Mandatory Reporting Rule factors and included in the CO_2e totals.

3. Similarly, the SCR catalyst may result in an increase in N_2O emissions. Although quantifying the increase is difficult, it is generally estimated to be very small or negligible. From the GHG emissions inventory, the estimated N_2O emissions from all combustion turbines total only 1.5 tpy. Therefore, even if there were an order-of-magnitude increase in N_2O as a result of the SCR, the impact to CO_2e emissions would be insignificant.

Use of the SCR and oxidation catalyst slightly decreases the project thermal efficiency due to backpressure on the turbines (these impacts are already included in the emission inventory) and, as noted above, may create a marginal but unquantifiable increase to N2O emissions. Although elimination of the NOx and CO/VOC controls could conceivably be considered as an option within the GHG BACT, the environmental benefits of the NOx, CO, and VOC control are assumed to outweigh the marginal increase to GHG emissions. Therefore, even if carried forward through the GHG BACT analysis, they would be eliminated in Step 4 because of other environmental impacts. Therefore, omission of these controls within the BACT analysis was not considered.

6.3.2 BACT Determination

The top-down GHG BACT determination for the combustion turbines and heat recovery steam generators with duct burners is presented below. Because the CTGs and HRSGs exhaust through a single stack, they were considered to be one combustion train for purposes of this BACT evaluation.

The primary GHG of concern for the Co-gen Project is CO_2. This analysis primarily presents the GHG BACT analysis for CO_2 emissions because CH_4 and N_2O emissions are insignificant, at less than 0.3 percent of facility GHG CO_2e emissions. No sources with SF_6, HFCs or PFCs pollutants are identified with this project. The switchgear will not require any changes. The primary sources of GHG emissions would be the natural gas-fired combustion turbines with duct burners.

This determination follows EPA's top-down analysis method, as specified in EPA's GHG Permitting Guidance (EPA, 2011b). The following top down analysis steps are listed in the EPA's *New Source Review Workshop Manual* (EPA, 1990):

- Step 1: Identify all control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies by control effectiveness
- Step 4: Evaluate most effective controls and document results
- Step 5: Select BACT

Each of these steps, described in the following sections, was conducted for GHG emissions from the CTGs and HRSGs with duct burners. The following top-down BACT analysis has been prepared in accordance with the EPA's *New Source Review Workshop Manual* (EPA, 1990) and takes into account energy, environmental, economic, and other costs associated with each alternative technology.

The previous and current emission limits reported for combined-cycle and cogeneration turbines were based on a search of the various federal, state, and local BACT, Retrofit Available Control Technology (RACT), and Lowest Achievable Emission Rate (LAER) databases. The search included the following databases:

- EPA BACT/LAER Clearinghouse (EPA, 2011c)
  - Search included the CO_2 BACT/LAER determinations for combined-cycle and cogeneration, large combustion turbines (greater than 25 MW) with permit dates for the years 2001 through 2011.
- BACT Analyses for Recently Permitted Combined-Cycle CEC Projects (CEC, 2011)
  - Review included the GHG BACT analysis for the Russell City Energy Center and the Palmdale Hybrid Power Project.

6.3.2.1. Identification of Available GHG Emissions Control Technologies – Step 1

There are three basic alternatives for limiting the GHG emissions from the nominal natural gas fired 38 MW turbines with duct burners:

- Carbon Capture and Storage (CCS)
- Thermal Efficiency
- Lower Emitting Alternative Technology

U.S. Borax has determined that the proposed co-gen plant with two natural-gas-fired CTGs with HRSGs and duct burners is the only alternative that meets all of the project objectives as further detailed in section 6.2. As such, other potentially lower emitting generation technologies such as wind and solar technologies were not evaluated in this BACT analysis. For similar reasons, geothermal, hydroelectric, nuclear and biomass-fueled plants are either not feasible given the U.S. Borax facility location or would change the fundamental business purpose of the Co-gen Project.

This is consistent with EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states:

> *EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility… (p. 26).*

The only identified GHG emission "control" options are post-combustion CCS and thermal efficiency of the proposed generation facility.

Carbon Capture and Storage

CCS technology is composed of three main components: (1) CO_2 capture and/or compression, (2) transport, and (3) storage.

CO_2 Capture and Compression

CCS systems involve use of adsorption or absorption processes to separate and capture CO2 from the flue gas, with subsequent desorption to produce a concentrated CO2 stream. The concentrated CO2 is then compressed to "supercritical" temperature and pressure, a state in which CO2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery or through ocean sequestration.

The capture of CO2 from gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure CO2 concentration, and contaminants in the gas or exhaust stream. Although CO2 separation processes have been used for years in the oil and gas industries, the characteristics of the gas steams are markedly different than power plant exhaust. CO2 separation from power plant exhaust has been demonstrated in large pilot-scale tests, but has not been implemented in full-scale power plant applications anywhere in the world.

After separation, the CO2 must be compressed to supercritical temperature and pressure for suitable pipeline transport and geologic storage properties. Although compressor systems for such applications are proven, commercially available technologies, specialized equipment is required, and operating energy requirements are very high.

CO_2 Transport

The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by ocean-going vessels.

Several geologic formations in California might provide a suitable site for geologic sequestration. The nearest potential sequestration basins to the U.S. Borax plant are north of the facility in the Lower San Joaquin Valley and west of the facility in Ventura County (National Energy Technology Laboratory [NETL], 2010). However, for both the San Joaquin Valley and Ventura County basins, there are significant mountain ranges that lie between the U.S.

Borax facility and potential sequestration sites, which would produce very costly transportation options for a CCS project.

CO_2 Storage

CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage has not been demonstrated in practice, as discussed below. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to enhance oil recovery in crude oil production operations.

Under geologic sequestration, a suitable geological formation is identified close to the proposed project, and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters). Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water that already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water, and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

As previously stated, potential sequestration sites have been located in the Lower San Joaquin Valley and in Ventura County (NETL, 2010). NETL states in the 2010 Carbon Sequestration Atlas that the highly fractured shale in the Ventura Basin is not a good candidate for CO_2 sequestration (NETL, 2010).

Although the San Joaquin Valley sites may eventually prove to be suitable, the geotechnical analyses needed to confirm their suitability have not been conducted. In addition, ocean storage is accomplished by injecting CO_2 into the ocean water typically below 1,000 meters via pipe or ship. At these depths, CO_2 is expected to dissolve or form into a horizontal lens, which would delay the dissolution of CO_2 into the surrounding environment. The depth of the overlying water and the lensing of the CO_2 will form a natural impediment to the vertical movement of the injected CO_2

Other potential CO_2 storage options include the use of a deep saline aquifer or depleted coal seams, or the use of compressed CO_2 to enhance oil recovery in crude oil production operations.

Thermal Efficiency

Because CO_2 emissions are directly related to the quantity of fuel burned, the less fuel burned per amount of energy produced (that is, greater energy efficiency) the lower the GHG emissions per unit of energy produced. As a means of quantifying feasible energy efficiency levels, the State of California established an emissions performance standard for power plants in the state. California Senate Bill 1368 limits long-term investments in baseload generation by the State's utilities to power plants that meet an emissions performance standard jointly established by the CEC and the CPUC. CEC regulations establish a standard for baseload generation (that is, project operating in excess of 4, 000 hr/yr) of 1,100 lbs (or 0.55 ton) CO_2 per MWh. This emission standard corresponds to a heat rate of approximately 9,400 Btu/kWh (CEC, 2010).

There are also significant efficiency gains to be derived from the cogeneration configuration. For example, the thermal electric generation processes lose 50 to 70 percent of the input fuel energy in the form of waste heat. Recovering this energy for steam or hot water production onsite or at a nearby facility increases the overall efficiency of the process from 30 to 50 percent to 70 to 80 percent (EPA, 2010). This reduction in fuel requirements translates directly to reduced GHG emissions per unit of energy on a lb/ Btu input basis. Furthermore, CEC issued Order No. 08-1217-16 on December 18, 2008 instituting a rulemaking proceeding to implement the Waste Heat and Carbon Emissions Reduction act, codified in Sections 2840 through 2845 of the Public Utilities Code. This rulemaking process is consistent with and furthers the objectives of the legislature, which found, in Public Resources Code Section 25004.2:

> *….cogeneration technology…should be an important element in the State's energy supply mix…can assist meeting the state's energy needs while reducing the long-term use of conventional*

> *fuels…reduces negative environmental impacts…and that cogeneration should receive immediate support and commitment from state government.* (CEC, 2010)

In addition, the Co-gen Project is a state-of-the-art, highly efficient co-gen plant that will not only reduce the CO_2 emissions on a pound-per-steam produced for the U.S. Borax production facility, but will also result in electricity that can be made available to the grid on short notice. This allows an increased use of wind power and other renewable energy sources, with backup power available from the Co-gen Project. A natural gas-fired co-gen plant such as the Co-gen Project uses a relatively small amount of electricity to operate the facility compared to the energy in the fossil fuel combusted. Therefore, there is negligible benefit in terms of energy efficiency and GHG emission reductions of the facility associated with lowering electricity usage at the facility compared to increasing the thermal efficiency of the process.

The addition of the high thermal efficiency of the Co-gen Project's generation to the state's electricity system will facilitate the integration of renewable resources in California's generation supply and will displace other less-efficient, higher GHG-emitting generation. Although the Co-gen Project would emit GHG emissions, the high thermal efficiency of the Co-gen Project and the U.S. Borax facility's ability to produce its own industrial process steam instead of the steam currently produced from the older, less-efficient onsite cogeneration facility and the Lakeshore Mojave plant would result in a net cumulative reduction of GHG emissions from new and existing fossil resources on a pounds of GHG per energy output basis.

California's Renewable Portfolio Standard (RPS) requirement was increased from 20 percent by 2010 to 33 percent by 2020, with the adoption of Senate Bill 2 on April 12, 2011. To meet the new RPS requirements, the amount of dispatchable, high-efficiency, natural gas generation used as regulation resources, fast-ramping resources, or load-following or supplemental energy dispatches will have to be significantly increased. The Co-gen Project will aid in the effort to meet California's RPS standard.

In summary, state-of-the-art technologies used in the GE LM6000 PC turbines with their highly efficient natural gas combustion; replacement of steam produced from the less efficient, older model turbines of the onsite generation and Mojave Lakeshore facilities with steam produced by the newer, more-efficient GE LM6000 turbines; and the ability to produce fast-ramping power to augment wind and other renewable power sources to the grid, make the Co-gen Project a highly energy efficient system.

6.3.2.2. Eliminate Technically Infeasible Options – Step 2

The second step for the BACT analysis is to eliminate technically infeasible options from the control technologies identified in Step 1. For each option that was identified, a technology evaluation was conducted to assess its technical feasibility. The technology is feasible only when the technology is available and applicable. A technology that is not commercially available for the scale of the project was considered infeasible. An available technology was considered applicable only if it can be reasonably be installed and operated on the proposed project.

Carbon Capture and Storage

Although many believe that CCS will allow the future use of fossil fuels while minimizing GHG emissions, there are a number of technical barriers concerning the use of this technology for the Co-gen Project at the U.S. Borax facility:

- No full-scale systems for solvent-based carbon capture are currently in operation to capture CO_2 from dilute exhaust steams such as those from natural gas-fired electrical generation systems.
- Use of captured CO_2 for enhanced oil recovery (EOR) is widely believed to represent the practical first opportunity for CCS deployment; however, identification of suitable oil reservoirs with the necessary willing and able owners and operators is not feasible for U.S. Borax to undertake. Given the relatively small levels of oil and gas production in the vicinity of the Co-Gen Project compared to other parts of the nation, identification of suitable EOR locations would be very challenging, and it is unlikely that any such locations would have adequate reservoirs for the captured CO_2 from the Co-gen Project.

- Little experience exists with other types of storage systems, such as deep saline aquifers (geological sequestration) or ocean systems (ocean sequestration). These storage systems are not a commercially available technology.
- Because of the developmental nature of CCS technology, vendors and contractors do not provide turnkey offerings; separate contracting would be required for capture system design and construction; compression and pipeline system routing, siting and licensing, engineering and construction; and geologic storage system design, deployment, operations, and monitoring. Because no individual facility could be expected to take on all of these requirements in order to implement a control technology, this demonstrates that the technology as a whole is not yet commercially available.
- Significant legal uncertainties still exist regarding relationship between land surface ownership rights and subsurface (pore space) ownership, potential conflicts with other uses of land such as exploitation of mineral rights, management of risks and liabilities, etc.
- Potential for frequent startup and shutdown of generation units at the U.S. Borax facility make CCS impractical for two reasons – inability of capture systems to start up in the same short time frame as combustion turbines, and infeasibility for potential users of the CO_2 such as EOR systems to use uncertain and intermittent flows. As described above, the co-gen units at the U.S. Borax facility are designed to accommodate rapidly fluctuating power and steam demands.

These issues are discussed in more detail below.

As suggested in the *EPA New Source Review Workshop Manual*, control technologies should be demonstrated in practice on full-scale operations in order to be considered available within a BACT analysis: "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice" (Draft, EPA, 1990). As discussed in more detail below, carbon capture technology has not been demonstrated in practice in power plant applications. Other process industries do have carbon capture systems that are demonstrated in practice, but the technology used for these processes cannot be applied to power plants.

Three fundamental types of carbon capture systems are employed throughout various process and energy industries: sorbent adsorption, physical absorption, and chemical absorption. Use of carbon capture systems on power plant exhaust is inherently different from other commercial-scale systems currently in operation, due in large part to concentration of CO_2 and other constituents in the gas streams.

For example, CO_2 is separated from petroleum in refinery hydrogen plants in a number of locations, but this is typically accomplished on the product gas from a steam CH_4reforming process that contains primarily hydrogen (H_2), unreacted CH_4, and CO_2. Based on the stoichiometry of the reforming process, the CO_2 concentration is approximately 80 percent by weight, and the gas pressure is approximately 350 pounds per square inch, gauge (psig). Because of the high concentration and high pressure, a pressure swing adsorption (PSA) process is used for the separation. In the PSA process, all non-hydrogen components, including CO_2 and CH_4, are adsorbed onto the solid media under high pressure; after the sorbent becomes saturated, the pressure is reduced to near atmospheric conditions to desorb these components. The CO_2/CH_4 mixture in the PSA tail gas is then typically recycled to the reformer process boilers to recover the heating value; but where the CO_2 is to be sold, an additional amine absorption process would be required to separate the CO_2 from CH_4. In its May 2011 *Department of Energy's (DOE)/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update*, NETL notes the different applications for chemical solvent absorption, physical solvent absorption, and sorbent adsorption processes. As noted in Section 4.B, "When the fluid component has a high concentration in the feed stream (for example, 10 percent or more), a PSA mechanism is more appropriate" (NETL, 2011)

In another example, at the Dakota Gasification Company's Great Plains Synfuels Plant in North Dakota, CO_2 is separated from intermediate fuel streams produced from gasification of coal. The gas from which the CO_2 is separated is a mixture of primarily hydrogen (H_2), CH_4, and 30 to 35 percent CO_2 and a physical absorption process

(Rectisol) is used. In contrast, as shown in the GE Guarantee in Appendix D, and as noted on page 29 of the *Report of the Interagency Task Force on Carbon Capture and Storage* (DOE and EPA,2010), CO_2 concentrations for natural-gas- fired systems are in the range of 3 to 5 percent. This adds significant technical challenges to separation of CO_2 from natural gas-fired power plant exhaust as compared to other systems.

In Section 4.A of the above-referenced technology update, NETL notes this difference between pre-combustion CO_2 capture such as that from the North Dakota plant versus the post-combustion capture such as that required from a natural-gas-fired power plant: "Physical solvents are well suited for pre-combustion capture of CO_2 from syngas at elevated pressures; whereas, chemical solvents are more attractive for CO_2 capture from dilute low-pressure post-combustion flue gas" (NETL, 2011).

The Interagency Task Force on Carbon Capture and Storage consists of 14 executive departments and federal agencies, co-chaired by DOE and EPA. In the 2010 report noted above, the task force discusses four currently operating post-combustion CO_2 capture systems associated with power production. All four are on coal-based power plants where CO_2 concentrations are higher (typically 12 to 15 percent), with none noted for natural gas-based power plants (typically 3 to 5 percent).

The DOE/NETL is a key player in the nation's efforts to realize commercial deployment of CCS technology. A downloadable database of worldwide CCS projects is available on the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/global/database/index.html). Filtering this database for projects that involve both capture and storage, which are based on post-combustion capture technology (the only technology applicable to natural gas turbine systems), which are shown as "active" with "injection ongoing" or "plant in operation," yields four projects. Three projects, one of which is a pilot-scale process noted in the interagency task force report as described above, are listed at a capacity of 274 tons per day (100,000 tpy) and the fourth has a capacity of only 50 tons per day. Post-combustion CCS has not been accomplished on a scale of even the modestly-sized U.S. Borax facility, which could produce up to approximately 502,000 tpy or 1,400 tons per day. Furthermore, scale-up involving a substantial increase in size from pilot scale to commercial scale is unusual in chemical processes and would represent significant technical risk.

As detailed in the August 2010 report, one goal of the task force is to bring 5 to 10 commercial demonstration projects online by 2016. With demonstration projects still years away, clearly the technology is not currently commercially available. It is notable that several projects, including those with DOE funding or loan guarantees, have been cancelled in recent months, making it further unlikely that technical information required to scale up these processes can be accomplished in the near future. For example, at the AEP Mountaineer site (noted above), the commercial-scale project was to expand capture capacity to 100,000 tpy, but to date only the "Project Validation Facility" was completed and only accomplished capture of a total of 50,000 metric tons and storage of 37,000 metric tons of CO_2. AEP recently announced that the larger project will be cancelled after completion of the front-end engineering design because of uncertain economic and policy conditions.

The interagency task force report notes the lack of demonstration in practice:

> *Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.* (DOE and EPA, 2010)

The ability to inject into deep saline aquifers as an alternative to EOR reservoirs is a major focus of the NETL research program. Although it is believed that saline aquifers are a viable opportunity, there are many uncertainties. Risk of mobilization of natural elements such as manganese, cobalt, nickel, iron, uranium, and barium into potable aquifers is of concern. Technical considerations for site selection include geologic siting, monitoring and verification programs, post-injection site care, long-term stewardship, property rights, and other issues. U.S. Borax is aware of at least one planned saline aquifer pilot project underway in the Lower San Joaquin

Valley near Bakersfield, CA (the Kimberlina Saline Formation), which may act as a possible candidate location for geologic sequestration and storage. According to the West Coast Regional Carbon Sequestration Partnership, a pilot project plant operated by Clean Energy Systems is targeting the Vedder Sandstone formation at a depth of approximately 8,000 feet, where there is beaded stream unit of saline formation that may be favorable for CO_2 storage. It is unclear when the project is planned for full scale testing and no plans are currently available to build a pipeline within the area to transport CO_2 to the test site. Presumably, the CO_2 would be available for EOR applications within the Lower San Joaquin Valley, but it is unclear the location, time frame, and needed flow rates for those existing or future EORs because this information is typically treated as trade secrets. Therefore U.S. Borax, as a developer of the facility, has no way of knowing when and if those future needs will be realized.

In regards to CO_2 storage security, the CCS task force report notes such uncertainties, "The technical community believes that many aspects of the science related to geologic storage security are relatively well understood. For example, IPCC concluded that "it is considered likely that 99 percent or more of the injected CO_2 will be retained for 1,000 years" (IPCC, 2005). However, additional information (including data from large-scale field projects, such as the Kimberlina project, with comprehensive monitoring) is needed to confirm predictions of the behavior of natural systems in response to introduced CO_2 and to quantify rates for long-term processes that contribute to trapping and, hence, risk profiles (for example, IPCC, 2005")". Field data from the Kimberlina CCS pilot project will provide additional information regarding storage security for that and other locations. Meanwhile, some uncertainties will remain regarding safety and permanence aspects of storage in these types of formations.

The effectiveness of ocean sequestration as a full-scale method for CO_2 capture and storage is unclear given the limited availability of injection pilot tests and the ecological impacts to shallow and deep ocean ecosystems. Ocean sequestration is conducted by injecting supercritical liquid CO_2 from either a stationary or towed pipeline at targeted depth interval, typically below 3,000 feet. CO_2 is injected below the thermocline, creating either a rising droplet or a dense phase plume and sinking bottom gravity current. Through NETL, extensive research is being conducted by the Monterey Bay Aquarium Research Institute on the behavior of CO_2 hydrates and dispersion of these hydrates within the various depth horizons of the marine environment, but the experiments are small in scale and the results may not be applicable to larger-scale injection projects in the near future. Long-term effects on the marine environment, including pH excursions, are ongoing, making the use of ocean sequestration technically infeasible at the current time. Furthermore, plans to build a pipeline to inject CO_2 from the U.S. Borax facility are not even in a conceptual design stage, making transportation nearly impossible in the near future (NETL, 2010).

CCS technology development is dominated by vendors who are attempting to commercialize carbon capture technologies and by academia-led teams (largely funded by DOE) that are leading research into the geologic systems. The ability for electric utilities to contract for turn-key CCS systems simply does not exist at this time.

Most current carbon capture systems are based on amine or chilled ammonia technology, which are chemical absorption processes. Although capture system startup and shutdown time of vendor processes could not be confirmed within this BACT analysis, clearly both types of processes would require durations that exceed the time required for U.S. Borax turbine startup or load response. As described above, U.S. Borax may start or stop turbines and duct firing, and adjust the load on the operating turbines rapidly to meet steam and electrical demands. In contrast, both amine and chilled ammonia systems require startup of countercurrent liquid-gas absorption towers and either chilling of the ammonia solution or heating of regeneration columns for the amine systems. It is technically infeasible for the carbon capture systems to startup and shutdown or make large adjustments in gas volume in the time frames required to serve this type of operation effectively, meaning that portions of the Co-gen operation would run without CO_2 capture even with implementation of a CCS system.

Finally, the potential to sell CO_2 to industrial or oil and gas operations is infeasible for an operation such as this, where daily operation of the co-gen system may depend on grid dispatch needs. Even if a potential EOR opportunity could be identified, such an operation would typically need a steady supply of CO_2. Intermittent CO_2 supply from potentially short-duration with uncertain daily operation would be virtually impossible to sell on the market, making the EOR option unviable. Therefore, CCS technology would be better suited for applications with low variability in operating conditions.

In the EPA PSD and Title V GHG permitting guidance, the issues noted above are summarized, "A number of ongoing research, development, and demonstration projects may make CCS technologies more widely applicable *in the future*" (EPA, 2011b; italics added). From page 36 of this guidance, it is noted:

> *While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long-term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard.*(EPA, 2011b)

Therefore, the CCS alternative is not considered technically feasible for the U.S. Borax project, and is eliminated from further consideration. Although it is eliminated based on the technical feasibility in Step 2, at the suggestion of EPA team members, economic feasibility issues will be covered in Step 4.

Thermal Efficiency

Thermal efficiency is technically feasible as a control technology for BACT consideration.

6.3.2.3. Combustion Turbine GHG Control Technology Ranking – Step 3

Because CCS is not technically feasible, the only remaining technically feasible GHG control technology for the Co-gen Project is thermal efficiency. While CCS will be further discussed in Step 4, and if it were technically feasible, would rank higher than thermal efficiency for GHG control, thermal efficiency is the only technically feasible control technology that is commercially available and applicable for the Co-gen Project.

6.3.2.4. Evaluate Most Effective Controls – Step 4

Step 4 of the BACT analysis is to evaluate the remaining technically feasible controls and consider whether energy, environmental, and/or economic impacts associated with the remaining control technologies would justify selection of a less-effective control technology. The top-down approach specifies that the evaluation begin with the most-effective technology.

Carbon Capture and Sequestration

As demonstrated in Step 2, CCS is not a technically feasible alternative for the Co-gen Project. Nonetheless, U.S. Borax understands that EPA has requested that CCS be further evaluated at Step 4. Control options considered in this step therefore include application of CCS technology and plant energy thermal efficiency. As demonstrated below, CCS is clearly not economically feasible for the Co-gen Project.

On page 42 of the EPA PSD and Title V Permitting Guidance, it is suggested that detailed cost estimates and vendor quotes should not be required where it can be determined from a qualitative standpoint that a control strategy would not be cost effective:

> *With respect to the valuation of the economic impacts of [U.S. Borax] control strategies, it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner. For instance, when evaluating the cost effectiveness of CCS as a GHG control option, if the cost of building a new pipeline to transport the CO_2 is extraordinarily high and by itself would be considered cost prohibitive, it would not be necessary for the applicant to obtain a vendor quote and evaluate the cost effectiveness of a CO_2 capture system.* (EPA, 2011b)

The guidance document also acknowledges the high costs of CCS technology at the current time:

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the technical feasibility of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the economical feasibility of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.*(EPA, 2011b)

The costs of constructing and operating CCS technology are indeed extraordinarily high, based on current technology. Even with the optimistic assumption that appropriate EOR opportunities could be identified in order to lower costs, compared to “pure” sequestration in deep saline aquifers, depleted coal seams, or through deep ocean storage, additional costs to U.S. Borax would include the following:

- Licensing of scrubber technology and construction of carbon capture systems
- Significant reduction to plant output due to the high energy consumption of capture and compression systems
- Identification of oil and gas companies holding depleted oil reservoirs with appropriate characteristics for effective use of CO_2 for tertiary oil recovery, and negotiation with those parties for long-term contracts for CO_2 purchases
- Construction of compression systems and pipelines to deliver CO_2 to EOR or storage aquifer locations
- Labor to operate, maintain, and monitor the capture, compression, and transport systems

The interagency task force report provides an estimate of capital and operating costs for carbon capture from natural gas systems: “For a [550 MWe net output] natural gas combined cycle (NGCC) plant, the capital cost would increase by $340 million and an energy penalty of 15 percent would result from the inclusion of CO_2 capture” (DOE and EPA, 2010). Using the ”Capacity Factor Method” for prorating capital costs for similar systems of different sizes as suggested by the Association for the Advancement of Cost Engineering and other organizations, CO_2 capture system capital cost for the U.S. Borax co-gen facility is estimated as at least $158 million. Based on an estimated co-gen facility capital cost of $107 million, the capture system alone would thus be expected to add approximately 148 percent to the overall plant capital cost.

As noted above, the effort required to identify and negotiate with oil and gas companies that may be able to utilize the CO_2 would be substantial. The location and operation of prospective EOR facilities within the area is unknown, making predictions for CO_2 demand generated by CCS difficult. And, due to the patchwork of oil well ownership, many parties could potentially be involved in negotiations over CO_2 value.

Owing to the extremely high pressures required to transport and inject CO_2 under supercritical conditions, the compressors required are very specialized. For example, the compressors for the Dakota Gasification Company system are of a unique eight-stage design. It is unclear whether the Task Force NGCC cost estimate noted above includes the required compression systems, but if not this represents another substantial capital cost.

Pipelines must be designed to withstand the very high pressures (over 2,000 psig) and potential for corrosion if any water is introduced to the system. As noted above, if CCS were otherwise technically and economically feasible for the U.S Borax facility, the most realistic scenario could be to construct a pipeline from Boron to Bakersfield to tie into the Clean Energy System pilot project (Kimberlina saline formation), assuming that it is eventually developed for commercial use. The approximate distance of the pipeline is 91 miles from Boron to the Bakersfield area. Based on engineering analysis by the designers of the Denbury CO_2 pipeline in Wyoming, costs for an 8-inch CO_2 pipeline to connect the Co-gen project to the Clean Energy System pilot project are estimated at $600,000 per mile, for a total cost of $54.6 million. Therefore the pipeline alone would represent a 78 percent increase to the project cost, and the pipeline and capture system together would nearly quadruple the project capital cost.

It is unlikely that financing could be approved for a project that combines CCS in conjunction with generation, given the technical and financial risks. Also, as evidenced with utilities' inability to obtain CPUC approval for integrated gasification / combined cycle (IGCC) projects because of their unacceptable cost and risk to ratepayers (such as Wisconsin's disapproval of the We Energy project), it is reasonable to assume that the same issues would apply in this case before the CPUC.

In summary, capital cost for capture system and pipeline construction alone would double the project capital cost, and lost power sales due to the CCS system energy penalty would represent another major impact to the project financials and a multi-fold increase to project capital costs. Other costs, such as identification , negotiation, and engineering of EOR opportunities; operating labor and maintenance costs for capture, compression, and pipeline systems; less-favorable financing terms or inability to finance; and difficulty in obtaining CPUC approval would also impact the project, and it is unclear if compression systems are included in the task force estimate of capture system costs. Not only is CCS not technically feasible, as the above discussion demonstrates, it is clearly not economically feasible for natural gas fired turbines at the current time.

Thermal Efficiency

Because CCS is not technically or economically feasible, thermal efficiency remains as the most effective, technically and economically feasible GHG control technology for the Co-gen Project. The turbines selected for the Co-gen Project are thermally efficient and compare favorably in terms of thermal efficiency with two recently permitted combined cycle natural gas-fired power plants.

A search of the EPA's RACT/BACT/LAER Clearinghouse was performed for combined-cycle and co-gen projects. No GHG permit information was found in searching the clearinghouse for comparable units. However, a GHG analysis was recently completed for the Russell City Energy Center and the Palmdale Hybrid Power Project in California. Both projects proposed the use of a combined-cycle configuration to produce commercial power, and the BACT analyses for both projects concluded that plant efficiency was the only feasible combustion control technology.

Table 6-2 is from the Palmdale permit application and shows that the Palmdale project is more efficient than other comparable power plant facilities in the Los Angeles Basin, using heat rate and GHG performance units as set forth in the table. US Borax has prepared a similar table, Table 6-3, to demonstrate that the US Borax Co-gen Project compares favorably (using these same metrics) with the Palmdale project and the Russell City project, the two projects identified above that have recently gone through a GHG BACT analysis. The combined effective heat rate and GHG performance of the Co-gen Project would be very similar to the Palmdale project despite the fact that the Palmdale project heat rate and GHG performance values are based on the inclusion of the energy generated from the solar generation component of the project. The U.S. Borax Co-gen Project effective heat rate and GHG performance were calculated assuming natural gas combustion and at maximum load for direct comparison purposes. The heat rate and GHG performance values for the Co-gen Project are also more efficient than the other facilities in the Los Angeles Basin (shown in Table 6-2) despite the fact that most of the projects near the top of the list are larger baseload industrial turbine facilities, which would be expected to have better efficiencies than the LM 6000 PCs (which are aero-derivative turbines) and because the industrial turbines are used in a baseload configuration, which is a fundamentally different configuration from the rapid turndown needs for turbines used in the Co-gen Project.

Thus taking into account the projects shown in Tables 6-2 and 6-3, the US Borax Co-gen Project is more energy efficient from a GHG perspective than other similar projects.

TABLE 6-2
Comparison of Heat Rates and Energy Outputs from Palmdale Application[1]

Plant Performance Variable	Heat Rate (Btu/kWh)	2008 Energy Output (GWh)	GHG Performance ($MTCO_2$/MWh)
Palmdale Hybrid Power Project	**6,970**	**4,993** [2]	**0.370**
Elk Hills Power, LLC	7,048	3,552	0.374
Pastoria Energy Facility LLC	7,025	4,905	0.384
La Paloma Generating	7,172	6,185	0.392
Sunrise Power	7,266	3,605	0.397
McKittrick Cogeneration Plant	7,732	592	0.422
Watson Cogeneration Company	8,512	3,017	0.452
Civic Center	9,447	467	0.501
Arco Products Co	10,140	477	0.538
Mandalay Generating Station	10,082	597	0.551
Alamitos	10,782	2,533	0.572
Huntington Beach (AES)	10,927	1,536	0.580
El Segundo Power	11,044	508	0.586
Carson Cogeneration Co	11,513	540	0.611
South Belridge Cogen Facility	11,452	409	0.625
Midway-Sunset Cogeneration	11,805	1,941	0.645
Sycamore Cogeneration Co	12,398	2,096	0.677
Kern River Cogeneration Co	13,934	1,258	0.761
Mt Poso Cogeneration (coal/pet.coke)	9,934	410	0.930

[1] From Tables 6-3 and 6-4 of the *Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis* (AECOM, 2011).

[2] The Palmdale Hybrid Power Project was not operational in 2008. The 2008 Energy Output number is based on the permitted design value.

TABLE 6-3
Comparison of Heat Rates and GHG Performance with Recently Permitted Projects

Plant Performance Variable	Heat Rate (Btu/kWh)	GHG Performance ($MTCO_2$/MWh)
U.S. Borax – Co-gen Project	**6,823** [1]	**0.363** [2]
Palmdale Hybrid Power Project	6,970 [3]	0.370 [3]
Russell City Energy Project	6,852 [4]	0.371 [5]

[1] Calculated HHV heat rate at 59 0F at site elevation of 2,400 feet, relative humidity of 30%, and no inlet air cooling

[2] Calculated CO2e emissions at conditions in footnote 1 above are 123,094 lb/hr with 154 combined MW (electrical + steam equivalent)

[3] From Tables 3 and 4 of the Palmdale Hybrid Power Project Greenhouse Gas BACT Analysis (AECOM, 2011)

[4] Net design heat rate with no duct firing, from "GHG BACT Analysis Case Study, Russel City Energy Center; November 2009, updated February 3, 2010.

[5] From Russell City total heat input of 4,477 MMBtu/hr (from PSD Permit), generation of 653 MW was calculated utilizing design heat rate of 6,852 Btu/kwh. From reference document in footnote 5 above, 1-hour CO2 limit is 242 MTCO2/hr, which yields 0.371 MTCO2/MWh.

This is further demonstrated by Table 6-4, which compares the thermal efficiency of the Russell City Energy project and the Palmdale project with the U.S. Borax Co-gen project.

TABLE 6-4
Comparison of Thermal Efficiencies with Recently Permitted Projects

Project Name	Facility Size (Nominal MW)	Thermal Efficiency (LHV) [1]
U.S. Borax – Co-gen Project	**76**	**____%** [2]
Palmdale Hybrid Power Project	530	56.5%[3]
Russell City Energy Project	550	55.8%[4]

[1] Calculated at ISO conditions
[2] Calculated using EPA guidance in determining thermal efficiency of cogeneration projects. (EPA 2010)
[3] From Palmdale BACT Analysis at 22. (AECOM 2011)
[4] From Palmdale BACT Analysis at 22. (AECOM 2011)

Using the thermal efficiencies for Russell City and Palmdale set forth in the Palmdale project BACT analysis (AECOM 2011), as compared with the thermal efficiency of the U.S. Borax Co-gen Project (as calculated using EPA's guidance for determining thermal efficiency of cogeneration projects, EPA 2010), demonstrates that the Co-gen Project is more thermally efficient than these two other recently permitted California projects that have undergone a GHG BACT analysis. It is important to note that the thermal efficiency numbers in Table 6-5 are for comparison purposes only and actual thermal efficiency may vary from the above estimates. Indeed, the Palmdale BACT analysis acknowledges this, as does the EPA guidance for calculating cogeneration thermal efficiencies. (EPA 2010). Accordingly, the Co-gen Project is BACT for GHGs, based on its favorable energy and thermal efficiencies as compared with other recently permitted gas turbine projects.

6.3.2.5. GHG BACT Selection – Step 5

Based on the above analysis, the only remaining feasible and cost-effective option is the "Thermal Efficiency" option, which, therefore, is selected as the BACT.

As shown above, the GE LM 6000 PC units compare favorably with other turbines and have sound thermal efficiency; this, coupled with the additional efficiencies gained by upgrading the current cogeneration units to the newer, more-efficient turbines and using these turbines to produce all of the steam for the U.S. Borax facility, rather than using existing steam generation sources (such as the existing co-gen and the Lakeshore Mojave facilities) that use older, less efficient combustion turbines, support the finding that the Co-gen Project using two GE LM6000 PC turbines is the BACT for GHG emission control

The LM6000 PC turbines will combust blended natural gas. The steam from the HRSG units will not be used to generate more power but will be used for the U.S. Borax refinery. Therefore, the thermal efficiency for the project is better measured in terms of pounds of CO_2e per MMBtu of energy output rather than pounds of CO_2e per kWh. This is in recognition that the co-gen units may operate with and without duct burners and that SCE may ask for U.S. Borax to curtail power production when solar and wind power is being maximized, maximizing the overall efficiency of the power grid. In this situation, the duct-firing for steam production would be misrepresented if the efficiency were measured based upon kWh or MWh.

The performance of all CTGs degrades over time. Typically turbine degradation at the time of recommended routine maintenance is up to 10 percent. Additionally, thermal efficiency varies up to 20 percent with turbine turndown and turbine/duct firing combinations. Finally, annual metrics for output-based limits on GHG emissions are affected by startup and shutdown periods because fuel is combusted before useful output of energy or steam. Therefore, the annual average thermal efficiency performance of any turbine will be greater than the optimal efficiency of a new turbine operating continuously at peak load by up to 35 percent over the lifetime of the turbine.

Therefore, taking into account the more-appropriate efficiency metric for co-gen projects of pounds of CO_2e per MMBtu of energy output and the inherent degradation in turbine performance over the life of the Co-gen Project, U.S. Borax has concluded that the BACT for GHG emissions is a limit of 230 pounds CO_2e/MMBtu of energy output, and a total annual CO_2e emissions limit of 552,925 tpy. Degradation over time and turndowns, startup, and shutdown are incorporated into these limits.

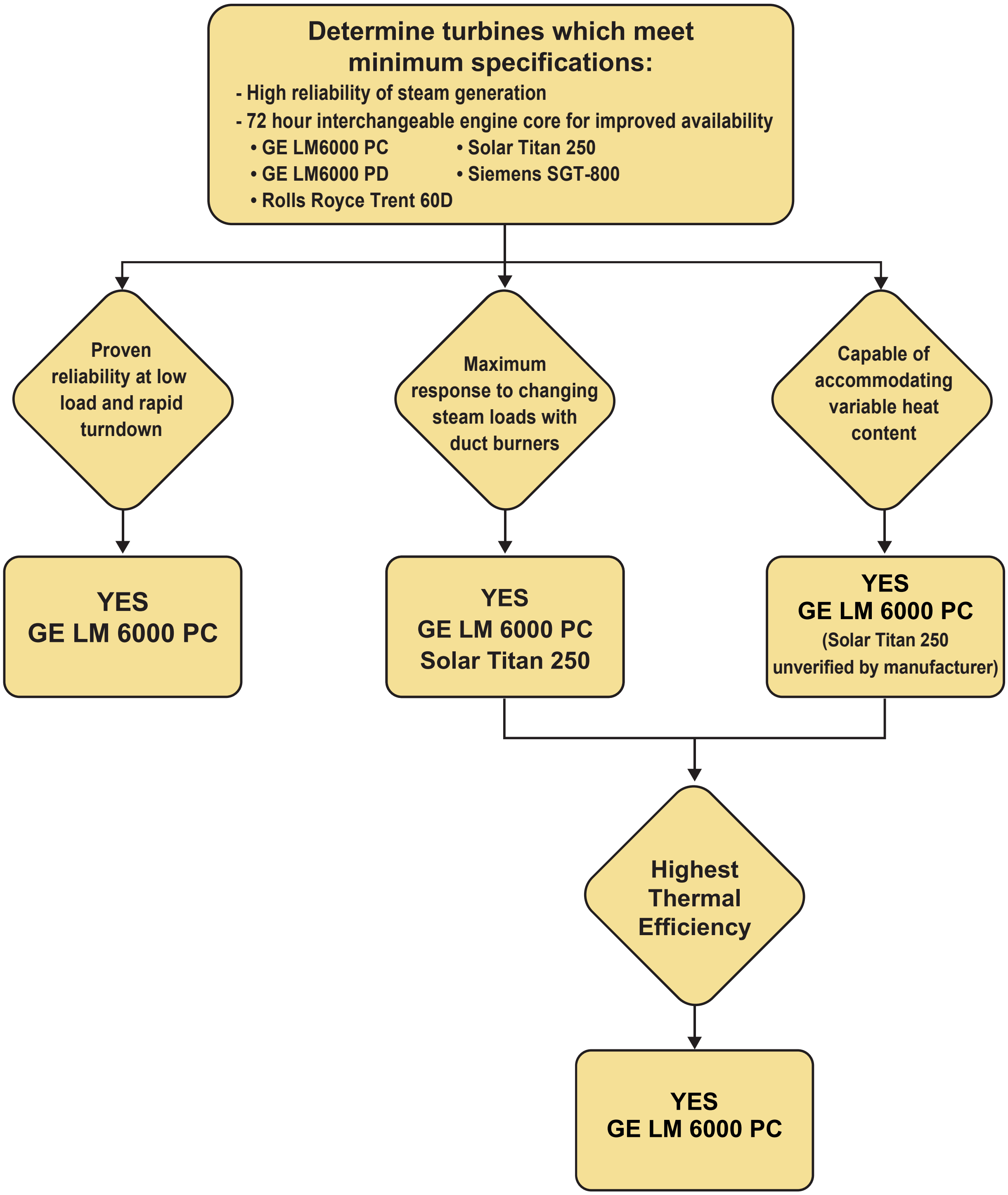

FIGURE 6-1
Combustion Turbine Comparison with Project Objectives
U.S. Borax Replacement Co-Generation Plant
Boron, California

SECTION 7

Air Quality Data, Air Quality Impact Analysis, Class I Impact Analysis, and Additional Impact Analysis

Localized GHG emissions are not known to cause adverse public health, welfare, or environmental impacts. Rather, EPA has chosen to regulate GHG emissions because these emissions are believed to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, National Ambient Air Quality Standards are not established for GHGs, and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Similarly, because there are no national standards and increments for GHGs, assessment of impacts to Class I areas is not a required element of this GHG PSD permit application.

All other pollutants regulated under PSD have a less–than-significant emissions increase and, in the case of NO_x, and CO, exhibit a decrease. Therefore, these pollutants are not subject to PSD review.. Similarly, GHG emissions are not regulated to address additional impacts under PSD, and no other analysis is required because the project is not subject to PSD for any other pollutant.

SECTION 8

Compliance with Other Regulations

8.1 Federal Regulations

The regulations established by EPA were reviewed for applicability to the Co-Gen Project. The federal regulations that are potentially applicable or deemed applicable are addressed in this section and include the proposed method of determining compliance with the rule requirements. The rules deemed not applicable based on regulation title are not discussed below.

8.1.1 40 CFR 70 – State Operating Permit Program

The current co-gen facility is covered in the Title V Permit as emission unit 077. A Title V permit application will be provided to EKAPCD within 12 months of startup of the replacement co-gen equipment.

8.1.2 40 CFR 64 – Compliance Assurance Monitoring

Compliance Assurance Monitoring is applicable for NO_x, CO, and VOCs because control devices will be used to meet emission standards. U.S. Borax plans on installing continuous emissions monitors for NO_x and CO to measure the performance of the oxidation catalyst and SCR units. Recordkeeping and reporting will be performed and submitted as required by regulation.

8.1.3 Title IV Requirements

The Co-Gen Project does not trigger compliance with acid rain requirements.

8.1.4 New Source Performance Standards Requirements

8.1.4.1. 40 CFR 60 Subpart A – General Provisions

The general new source performance standards (NSPS) provisions and definitions apply to the Co-gen Project as a part of the underlying NSPS that are applicable to the project. All monitoring, reporting, recordkeeping, and performance testing required by the individual NSPS will be accomplished and are outlined in the EKAPCD Form 201.1 – J in Appendix A.

8.1.4.2. 40 CFR 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

This regulation is not applicable because the co-gen operation is regulated under 40 CFR 60 Subpart KKKK.

8.1.4.3. 40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

This regulation is not applicable because the co-gen operation is regulated under 40 CFR 60 Subpart KKKK.

8.1.4.4. 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

The Co-gen Project is subject to this requirement because the combustion turbine heat input is higher than 10 MMBtu/hr, and the construction will take place after February 18, 2005. A continuous emission monitoring system will be installed to perform monitoring and recordkeeping to meet requirements of this subpart. Performance tests will be conducted initially and subsequently on an annual basis as defined in this subpart. Reports will be submitted semi-annually or more often as required by the regulation.

8.1.5 National Emission Standards for Hazardous Air Pollutants Requirements

8.1.5.1. 40 CFR 61 Subpart M – Asbestos

Demolition activities and disposal of construction-related materials containing asbestos will meet monitoring, recordkeeping, and reporting requirements as outlined in regulation when and if asbestos-containing materials are handled.

8.1.5.2. 40 CFR 63 Subpart YYYY - Combustion Turbines

This regulation is not applicable because U.S. Borax is not a major source for hazardous air pollutant (HAP) emissions because the facility PTE for HAPs does not exceed 10 tpy of any one HAP or 25 tpy of any aggregate of HAPS.

8.2 California Environmental Quality Act of 1970

California Environmental Quality Act of 1970 (CEQA) requirements will be addressed in a separate application package. A preliminary assessment of the project indicates that the project will not have any significant impacts and a negative declaration can be made. EKAPCD is developing new guidelines for CEQA requirements for GHG emissions. Under the proposed new policy, the Co-gen Project will not have significant GHG impacts.

8.3 CEC

U.S. Borax contacted the CEC regarding the Co-gen Project. On October 31, 2011, U.S. Borax received a letter from the CEC stating that the “new facility is not subject to Energy Commission jurisdiction”. The letter, by reference to an underlying judicial decision, clarifies that because the Co-gen Project results in a net power production increase of less than 50 MW, it is not subject to CEC review. A copy of this letter is attached as Appendix E.

SECTION 9

Endangered Species

Judy Hohman of the U.S. Fish and Wildlife Service (USFWS) Ventura office was contacted on October 19, 2011 as a follow up to discussions with EPA Region 9. The following summarizes the anticipated normal procedure as outlined in this discussion:

- Applicant submits PSD Application to EPA
- EPA performs the completeness review / determination
- EPA includes the Section 7 Consultation as a permit review / approval requirement
- Applicant submits the Project Description and any necessary supporting information to USFWS
- Applicant meets with the USFWS staff in Ventura to discuss the proposed action and project description
- EPA personnel do not usually participate in the consultation
- USFWS staff requests additional information, if necessary.
- Depending upon the size of the proposed action, USFWS personnel may visit the project site
- USFWS issues a letter conveying the results of the consultation to EPA
- EPA includes the USFWS letter in the supporting documentation for the PSD permit public comment and approval

This process will be followed after submittal of the PSD application.

SECTION 10

Public Notice Information

U.S. Borax anticipates the following agency contacts to be included in the public notification process for this permit:

- Eastern Kern Air Pollution Control District, 2700 M Street, Suite 302, Bakersfield, CA 93301
- Kern County Planning and Community Development Department. 2700 M Street #100, Bakerfield, CA 93301
- U.S. Fish & Wildlife Service, Federal Building, 2800 Cottage Way, Sacramento, CA 95825-1846

SECTION 11

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Appendix A
EKAPCD Application

Appendix B
Emission Calculations

Table B-1
U.S. Borax Netting Summary
February 2012

Maximum Annual Steady State Hours of Operation/CTG Only	8511	hours/year
Maximum Annual Steady State Hours of Operation/CTG plus DB firing	7218	hours/year
Maximum Starts and Shutdowns/CTG	12	events/year

	1 CTG				2 CTGs	Past Actual*	Difference (PTE - Past Actual)	EKAPCD Offset Trigger	Major Modification Level
Pollutant	**Steady Operation**	**Starts/stops**	**Total**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
NOx	33,607	385	33991.8	17.00	34.0	128	-94.3	25	25
CO	19,271	372	19643.5	9.82	19.6	133	-112.9	-	100
VOC	5,626	18	5644.0	2.82	5.6	4.5	1.1	25	25
SO2	12,434	14	12447.2	6.22	12.4	1.27	11.2	27	40
PM10	20,572	21	20592.9	10.30	20.6	10.7	9.9	15	15
PM2.5	20,572	21	20592.9	10.30	20.6	10.7	9.9	15	10

	PTE 2 CTG Total	Past ActualTurbine Total	Difference (PTE - Past Actual)	EPA PSD Permitting Threshold
Pollutant	**Metric TPY**	**Metric TPY**	**Metric TPY**	**Metric TPY**
CO2 Equivalent	501,610	236,838	264,772	75,000

*Past actual totals represent the maximum rolling 12 month total but do NOT include boiler emissions.
NOx Past Actual from January 2007 to December 2008.
CO Past Actual from August 2009 to July 2011
VOC Past Actual from August 2007 to July 2009
SO2 Past Actual from August 2008 to July 2010
PM10 and PM2.5 Past Actual from June 2009 to May 2011

Table B-2

U.S. Borax Estimated Performance

2x0 GE LM6000 PC Sprint Cogen Plant

CTG with No Duct Burner

February 2012

Case No.	Case 1	Case 2	Case 3	Case 4	Case 5
Plant configuration	2x0	2x0	2x0	2x0	2x0
CTG Load Point	100%	100%	100%	100%	100%
Ambient Temperature, oF	20	59	85	104	115
Relative Humidity, %	75	60	45	32	25
Evap Cooling	OFF	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	21,250	21,250	21,250	21,250	21,250

CT 1 Generator terminal power, kW	45,847	41,275	35,376	32,230	31,162
CT 1 Generator terminal power, kW	45,847	41,275	35,376	32,230	31,162
Gross Plant Power, kW	91,694	82,550	70,752	64,460	62,324
Gas Turbine 1 Fuel Input, MM Btu/Hr (LHV)	386.8	355.7	313.4	290.6	282.6
Gas Turbine 2 Fuel Input, MM Btu/Hr (LHV)	386.8	355.7	313.4	290.6	282.6
Duct Burner 1 Fuel input, MM Btu/Hr (LHV)	115.5	117.8	123.4	129.5	131.1
Duct Burner 2 Fuel input, MM Btu/Hr (LHV)	115.5	117.8	123.4	129.5	131.1
Total Fuel Input, MM Btu/hr (LHV)	1,004.6	947.0	873.6	840.2	827.4
Gross Plant Heat Rate, Btu/kWH (LHV)	10,956	11,472	12,347	13,034	13,276
HRSG 1 Steam Production, Lb/Hr at 165 psia	250,000	250,000	250,000	250,000	250,000
HRSG 1 Steam Production, Lb/Hr, at 165 psia	250,000	250,000	250,000	250,000	250,000
Total Steam Production, Lb/Hr, at 165 psia	500,000	500,000	500,000	500,000	500,000
CTG Heat Input - MMBtu/hr HHV (per turbine)	429	394	347	322	313

Exhaust Parameters at Each Stack

Flow, Lb/Hr	1,034,410	949,754	862,320	809,493	789,031
Temperature, F	242	237	234	232	232
Molecular Weight	28.1065	28.0682	27.9279	27.8683	27.8271
O2	0.1152	0.1322	0.1087	0.1057	0.1044
N2	0.7239	0.7206	0.711	0.7063	0.704
H2O	0.1117	0.1074	0.1295	0.1361	0.1397
CO2	0.0405	0.0312	0.0421	0.0434	0.0434
AR	0.0087	0.0086	0.0086	0.0084	0.0084
O2 % dry (calculated)	12.97	14.81	12.49	12.24	12.14

Uncorrected Pollutant Concentrations

NOx ppmvd	2.69	2.06	2.85	2.94	2.97
CO ppmvd	2.69	2.06	2.85	2.94	2.97
VOC ppmvd	1.34	1.03	1.43	1.47	1.49

CTG Emission Rates (No Duct Firing)

NOx Lb/hr	3.15	2.90	2.55	2.37	2.30
CO Lb/hr	1.92	1.76	1.55	1.44	1.40
VOC Lb/hr	0.55	0.50	0.44	0.41	0.40

Calculation Methodology

EPA Reference Method 19

E (lb/MMBtu) = Cd * Fd * ((20.9/(20.9-O2%))

Where Cd = Pollutant MW * 2.59*10^-9

Cd for NOx	1.1914E-07 lb/scf
Cd for CO	7.252E-08 lb/scf
Cd for VOC as methane	4.144E-08 lb/scf
Fd	8710 SDCF/MMBtu

Emissions	lb/Hr	lb/Day	lb/Year	TPY	TPY - 2 CTGs
NOx	3.2	75.6	26816	13.4	26.8
CO	1.9	46.0	16323	8.2	16.3
VOC	0.5	13.2	4664	2.3	4.7
SO2	1.2	28.0	9921	5.0	9.9
PM10	2.2	52.8	18724	9.4	18.7
PM2.5	2.2	52.8	18724	9.4	18.7

Assumptions

BACT Levels	Value	Units	
NOx	2.00	ppmvd @ 15% O2	
CO	2.00	ppmvd @ 15% O2	
VOC	1.00	ppmvd @ 15% O2	
SO2	0.00272	assuming 1 gr/100 scf and 1050 btu/scf	
CTG PM10	2.20	lb/hr	GWF Hanford and Henrietta BACT determinations
CTG PM2.5	2.20	lb/hr	GWF Hanford and Henrietta BACT determinations
F-Factor	8710.00	SDCF/MMBtu @ 0% O2	

Operations

CTG 8511

Hours/Year (8,511 hours of normal operations plus 9 hours of startup and shutdown (equivalent to 12 startup and 12 shutdown events)

Table B-3

U.S. Borax Estimated Performance

2x0 GE LM6000 PC Sprint Cogen Plant

CTG with Duct Burner

February 2012

Case No.	Case 1	Case 2	Case 3	Case 4	Case 5
Plant configuration	2x0	2x0	2x0	2x0	2x0
CTG Load Point	100%	100%	100%	100%	100%
Ambient Temperature, oF	20	59	85	104	115
Relative Humidity, %	75	60	45	32	25
Evap Cooling	OFF	ON	ON	ON	ON
Fuel Heating Value, Btu/Lb (LHV)	21,250	21,250	21,250	21,250	21,250

CT 1 Generator terminal power, kW	45,847	41,275	35,376	32,230	31,162
CT 1 Generator terminal power, kW	45,847	41,275	35,376	32,230	31,162
Gross Plant Power, kW	91,694	82,550	70,752	64,460	62,324
Gas Turbine 1 Fuel Input, MM Btu/Hr (LHV)	386.8	355.7	313.4	290.6	282.6
Gas Turbine 2 Fuel Input, MM Btu/Hr (LHV)	386.8	355.7	313.4	290.6	282.6
Duct Burner 1 Fuel input, MM Btu/Hr (LHV)	115.5	117.8	123.4	129.5	131.1
Duct Burner 2 Fuel input, MM Btu/Hr (LHV)	115.5	117.8	123.4	129.5	131.1
Total Fuel Input, MM Btu/hr (LHV)	1,004.6	947.0	873.6	840.2	827.4
Gross Plant Heat Rate, Btu/kWH (LHV)	10,956	11,472	12,347	13,034	13,276
HRSG 1 Steam Production, Lb/Hr at 165 psia	250,000	250,000	250,000	250,000	250,000
HRSG 1 Steam Production, Lb/Hr, at 165 psia	250,000	250,000	250,000	250,000	250,000
Total Steam Production, Lb/Hr, at 165 psia	500,000	500,000	500,000	500,000	500,000
CTG Heat Input - MMBtu/hr HHV (per turbine)	429	394	347	322	313
DB Heat Input - MMBtu/hr HHV (per unit)	128	131	137	143	145
Total Heat Input - MMBtu/hr HHV (per unit)	557	525	484	465	458

Exhaust Parameters at Each Stack

Flow, Lb/Hr	1,034,410	949,754	862,320	809,493	789,031
Temperature, F	242	237	234	232	232
Molecular Weight	28.1065	28.0682	27.9279	27.8683	27.8271
O2	0.1152	0.1322	0.1087	0.1057	0.1044
N2	0.7239	0.7206	0.711	0.7063	0.704
H2O	0.1117	0.1074	0.1295	0.1361	0.1397
CO2	0.0405	0.0312	0.0421	0.0434	0.0434
AR	0.0087	0.0086	0.0086	0.0084	0.0084
O2 % dry (calculated)	12.97	14.81	12.49	12.24	12.14

Uncorrected Pollutant Concentrations

NOx ppmvd	2.69	2.06	2.85	2.94	2.97
CO ppmvd	2.69	2.06	2.85	2.94	2.97
VOC ppmvd	2.69	2.06	2.85	2.94	2.97

CTG Emission Rates

NOx Lb/hr	3.15	2.90	2.55	2.37	2.30
CO Lb/hr	1.92	1.76	1.55	1.44	1.40
VOC Lb/hr	1.10	1.01	0.89	0.82	0.80

DB Emission Rates

NOx Lb/hr	0.9	1.0	1.0	1.1	1.1
CO Lb/hr	0.4	0.5	0.3	0.3	0.3
VOC Lb/hr	0.1	0.2	0.1	0.1	0.1

Calculation Methodology

EPA Reference Method 19

E (lb/MMBtu) = Cd * Fd * ((20.9/(20.9-O2%))

Where Cd = Pollutant MW * 2.59*10^-9

Cd for NOx	1.1914E-07	lb/scf
Cd for CO	7.252E-08	lb/scf
Cd for VOC as methane	4.144E-08	lb/scf
Fd	8710	SDCF/MMBtu

	Turbines PLUS Duct Burners		Duct Burners ONLY		
Emissions	**lb/Hr**	**lb/day**	**Lb/Year**	**TPY**	**TPY - 2 CTGs**
NOx	4.1	98.2	6791	3.4	6.8
CO	2.3	55.8	2949	1.5	2.9
VOC	1.2	29.5	963	0.5	1.0
SO2	1.5	36.3	2512	1.3	2.5
PM10	2.5	58.9	1847	0.9	1.8
PM2.5	2.5	58.9	1847	0.9	1.8

Note: The annual PM10 and PM2.5 duct burner emissions were based on the heat input for 20 degree F.

Assumptions

BACT Levels	Value	Units	
NOx	2.00	ppmvd @ 15% O2	
CO	2.00	ppmvd @ 15% O2	
VOC	2.00	ppmvd @ 15% O2	
SO2	0.00272	lb/MMBtu assuming 1 gr/100 scf and 1050 btu/scf	
CTG PM10	2.20	lb/hr	GWF Hanford and Henrietta BACT determinations
CTG PM2.5	2.20	lb/hr	GWF Hanford and Henrietta BACT determinations
DB PM10	0.002	lb/MMBtu	Duct Burner EF from Tracy
DB PM2.5	0.002	lb/MMBtu	Duct Burner EF from Tracy
F-Factor	8710.00	SDCF/MMBtu @ 0% O2	

Operations

Duct Burner 7218 Hours/Year

Table B-4
U.S. Borax Co-gen Project
Startup and Shutdown Emission Estimates
February 2012

Assumptions	Value	Units	Notes
Total Start Up Duration	30	minutes	Includes 10 minutes of turbine startup to full load (GE Curve) and an additional 20 minutes for SCR/Oxidation Catalyst warm up.
Total Shutdown Duration	15	minutes	Includes 7 minutes prior to the 8 minute turbine shutdown period (GE Curve).
SCR/Ox Cat Start Up Duration	20	minutes	SCR/Ox Cat warm up period after turbine start of 10 minutes.
SCR/Ox Cat Shutdown Duration	7	minutes	Additional SCR/Ox Cat shutdown period in addition to the 8 minute GE shutdown curve.
Starts/Shutdowns/Day	1	each	
Starts/CTG/Year	12	each	
Shutdown/CTG/Year	12	each	

	Emission Rate (pound per period)			
Intial Startup/Shutdown	**NOx**	**CO**	**VOC**	**Reference**
Startup Emission Data	3.5	3.0	0.058	Initial 10 minutes - GE LM6000 Start Curve at ISO Conditions
Shutdown Emission Data	2.7	2.4	0.047	Final 8 minutes - GE LM6000 Shutdown Curve at ISO Conditions

Maximum Hourly Emission Rate (Steady State)

	NOx (lb/hr)	CO (lb/hr)	VOC (lb/hr)	NOx (lb/min)	CO (lb/min)	VOC (lb/min)
without SCR/Ox Cat control	38.79	59.04	2.90	0.647	0.984	0.048
with SCR/Ox Cat control (no DB)	3.15	1.92	0.55	0.053	0.032	0.009
with SCR/Ox Cat control and DB	4.09	2.33	1.23	0.068	0.039	0.020

	Start up/Shutdown Emissions Estimate per CTG								
	Start	Shutdown	Single Start[d]	Single Shutdown[d]	Combined Start-up/Shutdown[e]	Starts Only[f]	Shutdowns Only[f]	Starts Only[g]	Shutdowns Only[g]
Pollutant	Lb/Event[a, b]	Lb/Event[c]	Lb/Hour	Lb/Hour	Lb/Hr	Lb/Day	Lb/Day	Lb/Year	Lb/Year
NOx	12.9	3.2	14.9	6.2	17.1	12.9	3.2	154.4	38.1
CO	12.8	2.7	14.0	4.4	16.1	12.8	2.7	154.1	32.1
VOC	0.5	0.19	1.2	1.1	1.0	0.5	0.2	6.5	2.3

[a] NOx lb/event is calculated as: (3.5 pounds during initial period + (14/20 minutes*uncontrolled NOx emission rate)+(6/20 minutes * controlled emission rate))
[b] The CO and VOC lb/event value assumes the control efficiency of the oxidation catalyst increases linearly from minute 10 through minute 30 of the startup event.
[c] Shutdown lb/event values are calculated as ((7 minutes * controlled emission rate w/ DB firing) + (emissions during final 8 minutes))
[d] The single start and shutdown hourly emission rates assumes one start or one shutdown per hour with the remainder of the hour at the maximum controlled emission rate with DB firing.
[e] The combined start-up/shutdown emission rate represents the 1-hour emission rate assuming one 30-minute turbine start-up, 15 minutes of the maximum controlled emission rate
[f] Daily emission rate only includes the emissions for 1 startup or 1 shutdown events (i.e., does not include hours for steady-state operation)
[g] Annual emission rate only includes the emissions for 12 startups and shutdown events (i.e., does not include hours for steady-state operation)

	Start up/Shutdown Emissions Estimate for 2 CTG				
	Start	Shutdown	Start	Shutdown	Start/Stop
Pollutant	Lb/Day	Lb/Day	Lb/Year	Lb/Year	TPY
NOx	25.7	6.4	308.8	76.3	0.19
CO	25.7	5.3	308.2	64.1	0.19
VOC	1.1	0.4	13.0	4.6	0.009

Table B-5
U.S. Borax Co-gen Project
Turbine GHG Emission Estimates
February 2012

CO2 equivalent Emissions Factors

	Case No.				
	Case 1	Case 2	Case 3	Case 4	Case 5
Turbine (MMBtu/hr per unit)	429	394	347	322	313
Duct Burner (MMBtu/hr per unit)	128	131	137	143	145
Facility Total (MMBtu/hr per unit)	557	525	484	465	458
Turbine CO2 Equivalent Emissions (lb/hr - project)	103,590	95,261	83,932	77,826	75,684
Duct Burner CO2 Equivalent Emissions (lb/hr - project)	30,932	31,548	33,048	34,682	35,110
Total CO2 Equivalent Emissions (lb/hr - project)	134,522	126,809	116,980	112,508	110,794

CO2 equivalent emissions (metric tons/year) = [CO2 emissions] + [CH4 emissions x CH4 GWP] + [N2O emissions x N2O GWP]

Facility Heat Input (RT-2 - 20F)

Turbine Natural Gas Use - Facility (PTE)	7,302,663	MMBtu/yr	
DB Natural Gas Use - Facility (PTE)	1,847,337	MMBtu/yr	
Turbine Natural Gas Use (PTE):	9,150,000	MMBtu/yr	(2 Turbines plus DB Firing)
Turbine Natural Gas Use - Facility (Past Actuals):	4,320,221	MMBtu/yr	(Turbine plus DB Firing) Natural gas use changed based on client request

GHG Netting

	Emissions (metric tons/year)	Past Actuals (metric tons/year)	Difference (metric tons/year)	Turbine OnlyEmissions (metric tons/year)	Emissions (tons/year)	Past Actuals (tons/year)	Difference (tons/year)
CO2	500,597	236,359	264,237	399,529	551,808	260,539	291,269
CH4	35	16.42	18	28	38	18	20
N2O	0.9	0.43	0.5	0.73	1	0	1
CO2 Equivalent (Total)	501,610	236,838	264,772	400,338	552,925	261,066	291,859

GHG Emission Factors

	Emission Factor (kg/MMBtu)	
CO2	54.71	Based on LNG combustion
CH4	0.0038	
N2O	0.0001	

CO2 emission factor from Table 12.1 The Climate Registry General Reporting Protocol, natural gas with >1,100 Btu heat input for LNG

CH4 and N2O emission factors from Source: IPCC, Guidelines for National Greenhouse Gas Inventories (2006), Chapter 2: Stationary Combustion, Table 2.7. Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for coal and oil, 10 percent lower for natural gas, and 20 percent lower for dry wood. (The IPCC converted the original factors from units of HHV to LHV, so the same conversion rates used by the IPCC were used here to obtain the original values in units of HHV.) Values were converted from kg/TJ to g/MMBtu using 1 kg = 1000 g and 1 MMBtu = 0.001055 TJ. NA = data not available.

Global Warming Potential

CH4	21
N2O	310

Reference: Intergovernmental Panel on Climate Change, Second Assessment Report (IPCC, 1996)

Table B-6

U.S. Borax Co-gen Project

Turbine Air Toxics Emission Estimates

February 2012

Assume:

Unfired Operations Hours/Year	8520	Hours/Year (8,511 hours of normal operations plus 12 startup and shutdown events)
Gas Heat Content =	1051.9	MMBtu/MMSCF
Hourly CTG Heat Input (per unit)	428.6	MMBtu/Hr high heating value (HHV)
Hourly CTG Heat Input (per unit)	0.407	MMCF/Hr
Annual CTG Heat Input (per unit)	3471	MMCF/Yr
Fired Operations Hours/Year	7218	
Gas Heat Content =	1051.9	MMBtu/MMSCF
Hourly CTG Heat Input (per unit)	128.0	MMBtu/Hr high heating value (HHV)
Hourly CTG Heat Input (per unit)	0.122	MMCF/Hr
Annual CTG Heat Input (per unit)	878	MMCF/Yr

					Turbine Emissions					
Compound	**Emission Factor (Lb/MMBTU)**	**Emission Factor (Lb/MMCF)[a]**	**Maximum CTG and DB Heat Input (mmBtu/hr)**	**CTG and DB Gas Input (MMCF/hr)**	**lb/hr/CT & DB**	**lb/hr/2-CT &DB**	**lb/yr/CT & DB**	**TPY/CT & DB**	**lb/yr/2-CT & DB**	**TPY/2-CT & DB**
Ammonia										
Ammonia[b]	--	5 ppm	557	0.529	3.8	7.6	31140.5	15.6	62281	31.1
HAPS										
Acetaldehyde	--	0.137	557	0.529	0.07	0.14	596	0.30	1192	0.60
Acrolein[a]	6.70E-06	--	557	0.529	0.004	0.007	30.7	0.0153	61.3	0.031
Benzene	--	0.0133	557	0.529	0.007	0.01	57.8	0.029	116	0.058
1,3-Butadiene	--	0.000127	557	0.529	0.0001	0.0001	0.55	0.00028	1.1	0.00055
Ethylbenzene	--	0.0179	557	0.529	0.01	0.02	77.9	0.039	156	0.078
Formaldehyde	--	0.917	557	0.529	0.5	1	3988	2.0	7977	4.0
Hexane	--	0.259	557	0.529	0.1	0.3	1126	0.56	2253	1.1
Naphthalene	--	0.00166	557	0.529	0.001	0.002	7.2	0.0036	14	0.0072
PAHs[c]	--	0.000014	557	0.529	0.01	0.029	0.061	0.000030	0.12	0.000061
Propylene	--	0.771	557	0.529	0.4	1	3353	1.7	6707	3.4
Propylene Oxide	--	0.0478	557	0.529	0.03	0.1	208	0.10	416	0.21
Toluene	--	0.071	557	0.529	0.04	0.1	309	0.15	618	0.31
Xylene	--	0.0261	557	0.529	0.01	0.03	114	0.057	227	0.11
TOTAL HAPs							**9868**	**4.93**	**19737**	**9.87**

Notes:

[a] Obtained from the California Air Toxics Emission Factors (CATEF) database with the exception of acrolein. According to the ARB CATEF website, the ARB does not recommend using the acrolein emission factors until the questions related to the acrolein sampling method are resolved. Therefore, the acrolein emission factor from AP-42 (April 2000) was used (Table 3.1-3)

[b] Based on the exhaust NH_3 limit of 5 ppmv @ 15% O_2 and a F-factor of 8710.

[c] Carcinogenic PAHs only; naphthalene considered separately. Emission Factor based on two separate source tests (2002 and 2004) from the Delta Energy Center located in Pittsburg, CA.

Appendix C
Power Engineers Report

November 16, 2010

RIO TINTO MINERALS BORON OPERATIONS

New Cogeneration Facility

Feasibility Study

PROJECT NUMBER:
120599

PROJECT CONTACT:
Donald Marshall
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360-348-7430

POWER ENGINEERS

Feasibility Study

PREPARED FOR: *RIO TINTO BORON OPERATIONS*
PREPARED BY: *DONALD MARSHALL*
360-348-7430
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REVISION HISTORY		
DATE	**REVISED BY**	**REVISION**
10/25/2010	D. Marshall	A – Issued for Review
11/2/2010	S. Harris	B – Revised the single unit heat balances contained in Appendix I to increase duct firing and steam flow.
11/15/2010	S. Harris/D. Marshall	C – Changed references on power sales and demineralized water. Added comments on LM6000 PF gas turbine generator.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

POWER Engineers was retained by Rio Tinto Minerals – Boron Operations (aka U.S. Borax) to perform an engineering study to confirm an earlier feasibility study that examined repowering their existing 45 MW cogeneration plant at the Rio Tinto Borax mining and refining facility in Boron, California. The existing cogeneration plant provides process steam and electrical power to the facility and sells excess electricity to Southern California Edison and Clean Energy's LNG Plant adjacent to the U.S. Borax facility. Additional process steam is purchased on an as needed basis from an adjacent privately owned cogeneration power plant, Mojave Cogeneration. Both the existing facility cogeneration power plant and Mojave Cogeneration are based on Westinghouse W 251 combustion gas turbine generators. The facility cogeneration power plant was constructed in 1983.

Mojave Cogeneration is operating under the terms of a power purchase contract that will expire in September 2013. With the age of its equipment, and with a high heat rate compared to modern equipment, Mojave Cogeneration might not remain in operation after expiration of its power contract. As a result Rio Tinto Minerals has decided to plan for that possibility by studying a replacement source of steam. At the same time, Rio Tinto Minerals is also considering repowering its own cogeneration equipment with more efficient equipment. The repowered facility cogeneration power plant will provide 100% of the required process steam and produce electrical energy more economically with modern generation equipment.

During the course of the study several key issues were identified that resulted in modifications to the previously recommended configuration. These key issues were:

1. Reliable steam generation is critical to the operation of the Rio Tinto Minerals facility. In addition, these steam loads can change rapidly. Taken together, the repowered cogeneration plant, like the existing plants, must have a high degree of reliability and turndown. The existing plants accommodate the swings in steam load through a combination of duct firing, bypassing turbine exhaust gas so as not to generate steam, adjusting turbine load, and using auxiliary boilers. With the repowered plant, the ability to bypass turbine exhaust gas will be lost as all of the exhaust gas must pass through the heat recovery steam generator (HRSG) where it is also treated to reduce emissions. As the need for steam is greater than electricity, the loss of the gas bypass capability combined with the turndown limitations, placed a greater demand on the other methods to vary steam generation. This drove a strategy of relying on significant duct firing which can be quickly modulated over the full range

2. Approximately half of the gaseous fuel supplied to the existing and future cogeneration plant is refinery fuel gas (RFG) supplied from a nearby Clean Energy LNG plant. The RFG is blended with pipeline quality natural gas. The resulting fuel mix can vary in energy content, sometimes rapidly. The existing W251 turbines are of older technology and more forgiving of a varying fuel mix than some current technology engines. In particular, some turbines are not suitable for this fuel, including the originally selected LM6000 PD Dry Low NOx turbines. Thus the study was expanded to look at other more suitable turbines

For the purposes of the study – to confirm the basic approach of repowering - a configuration of two General Electric LM6000 PC turbines was selected. These turbines utilize water injection into the combustion section making them more tolerant of the varying fuel than the dry low NOx version. Additionally, their size allowed the use of significant duct firing to accommodate steam load swings.

While permitting through the California Energy Commission is not expected since the output of the repowered two unit cogeneration plant will represent a less than 50 MW increase over the capacity of the existing single unit cogeneration plant operated by Rio Tinto, permitting with local agencies and the air district will still be required. Given the baseload operation of the cogeneration plant and consequent annual emissions, it is very likely that the project will be subject to US EPA permitting. As a consequence, an 18-24 month permitting duration can be expected. As a result our schedule study demonstrated that with an immediate start and assuming a normal construction schedule, the repowering project is not expected to complete until December 2013.

A scoping EPC level cost estimate was also developed for the studied configuration. This cost is exclusive of owner soft costs such as permitting and interconnection fees, emissions offsets, financing costs, and other owner costs. The estimated cost for completion of this project is $101,837,000.

STUDY METHODOLOGY

This report provides the assessments, conclusions, and recommendations of POWER Engineers' study of the Rio Tinto Boron facility, the existing cogeneration plant, and possible equipment configurations for repowering the cogeneration plant. POWER's study of the project commenced with a site visit on August 11, 2010. Appendix A contains the report of the site visit and a selection of photographs taken during the visit.

With the natural gas/RFG fuel mixture issue that was identified during the site visit, the possible engines to consider for the repowering were expanded. This led to an additional study element contained in Appendix B which provides the results of the initial set of gas turbine equipment and configurations that were evaluated. The result of this study in conjunction with discussions with the Rio Tinto staff was to settle upon the LM6000 PC – a water injected engine – for the purposes of the completing the feasibility study.

With the engine and plant configuration selected, POWER developed heat and mass balances to describe expected operational characteristics (Appendix I). POWER then developed a set of functional criteria for the project (Appendix C), a conceptual site plan drawing to illustrate the repowered cogeneration facility (Appendix D), and a conceptual one-line drawing (Appendix E) to broadly define the project. With this complete, a list of major equipment required for the New Cogeneration Facility was then developed (Appendix F).

POWER then proceeded to obtain equipment budgetary quotations to support development of project cost and schedule estimates. Appendix G contains a schedule of project development, engineering, procurement, construction, and commission activities required to implement the repowering project. Appendix H is an estimate of the engineering, procurement, and construction costs for the New Cogeneration Facility. The heat & mass balance diagrams for the proposed plant configuration at various operating conditions are contained in Appendix I.

FACILITY DESCRIPTION

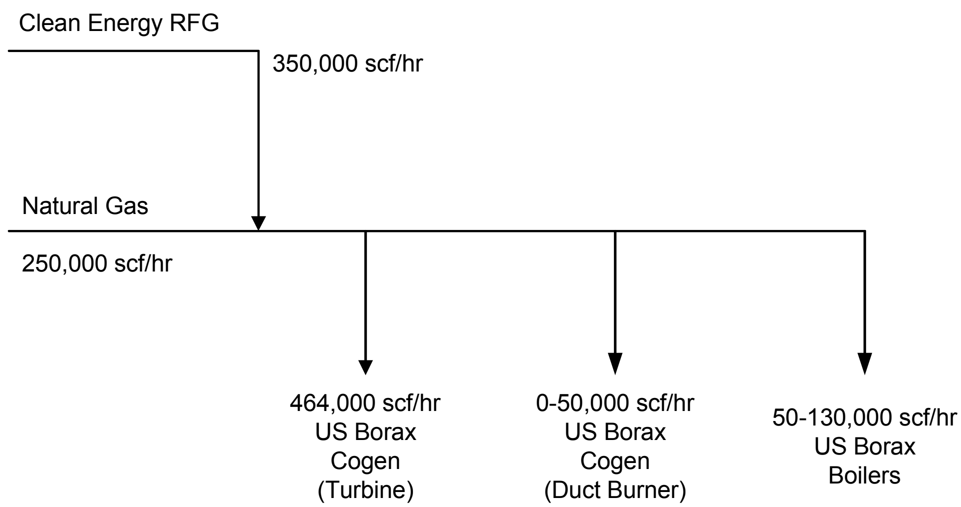
The Rio Tinto US Borax facility is located at the north end of Borax/Suckow Road, north of Highway 58 at 14486 Borax Road, Boron, California 93516-2000.

Rio Tinto's Boron Operations ("US Borax") relies on process steam from two cogeneration plants for its boron processing operations. One of the cogeneration plants is owned by US Borax, the other by Mojave Cogeneration which sells steam and demineralized water under contract to US Borax, and in turn receives feed water from US Borax. The demineralized water supplied by Mojave Cogeneration is used by US Borax for its cogeneration plant.

Both cogeneration plants utilize Westinghouse 251 gas turbines with HRSGs. The US Borax HRSG is equipped for duct firing. The Mojave Cogeneration unit does not have duct firing, but does operate in combined cycle with a steam turbine. As the electricity produced in conjunction with producing the required steam exceeds the needs of US Borax, the excess electricity is sold to Southern California Edison and the neighboring Clean Energy LNG plant.

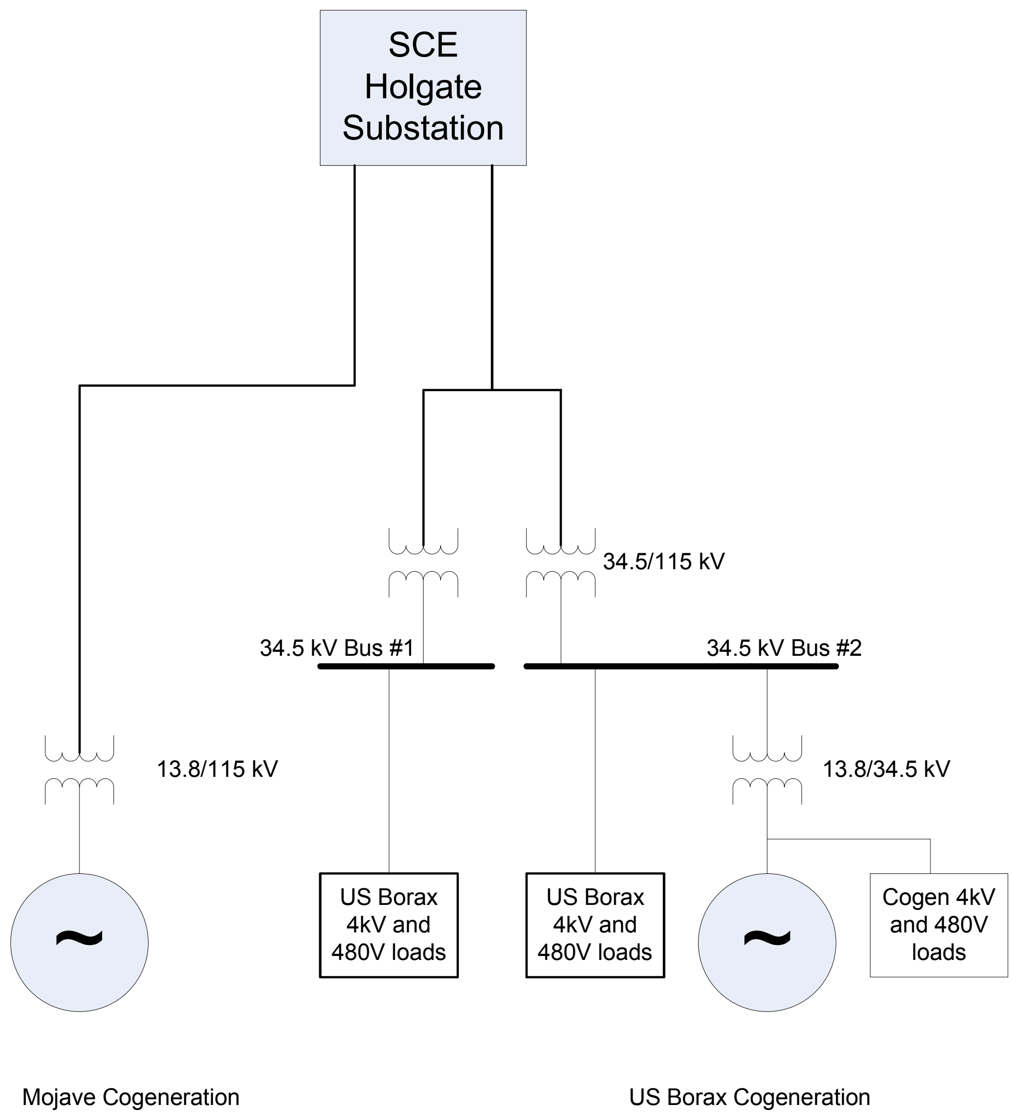
Pipeline quality natural gas for both cogeneration plants is supplied from a nearby natural gas transmission pipeline. While the supply pressure does vary between 600-850 psig, a typical minimum value is 700 psig. In addition, the Clean Fuels LNG plant also provides a fuel gas stream to US Borax of 350,000 scf/Hr of gas with a minimum methane content of 90.5%. The remaining 10% can contain heavier hydrocarbons. The energy content of the gas varies from 900-1,200 Btu/scf (natural gas is ~1,000 Btu/scf)

FUEL GAS SOURCES & DISTRIBUTION

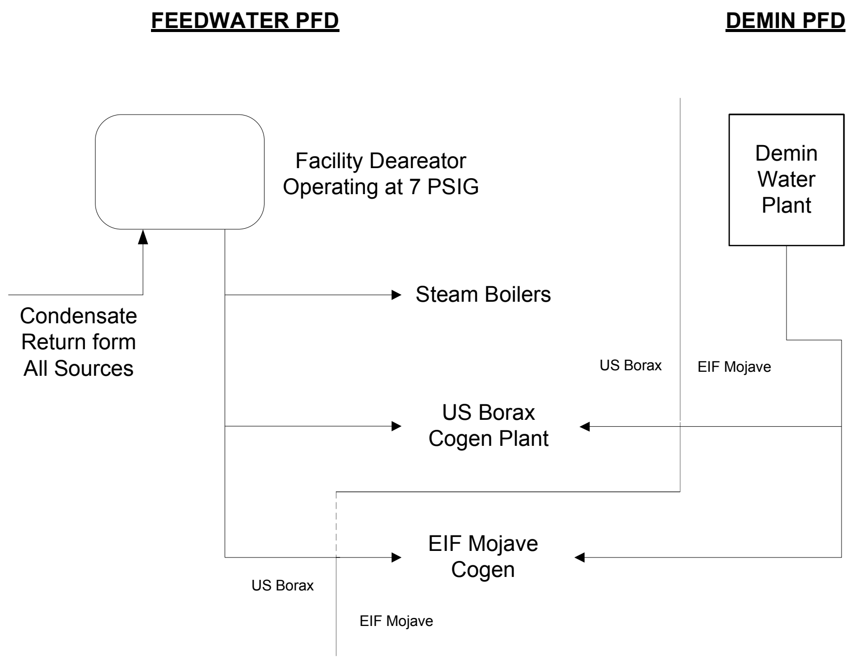


The electrical output from the US Borax cogeneration plant is delivered to the facility's 34.5 kV Bus #2. That bus is cross-tied to Bus #1, and from both buses power is delivered to the facility loads. A step-up transformer will deliver excess power from the 34.5 kV bus to the 115 kV transmission line connecting to Southern California Edison's Holgate Substation. The electrical output from Mojave Cogeneration plant is delivered directly to SCE's Holgate substation via an underground/overhead 115 kV transmission line.

ELECTRICAL SCHEMATIC



US Borax supplies potable water to both the US Borax and EIF Mojave cogeneration plants for make-up. The EIF Mojave Cogeneration plant produces its own demineralized make-up water which is also supplied to the US Borax cogeneration plant. Feedwater for the US Borax boilers,US Borax cogeneration plant and Mojave Cogeneration is supplied from a central deaerator operating at 7 psig. With the termination of the contract between the US Borax facility and Mojave Cogeneration, US Borax will need to supply its own demineralized water for the cogeneration plant



Steam is supplied for process use at a pressure of 150 psig with a maximum of 10 ^{o}F superheat. The US Borax facility steam loads vary over the course of the year and as processing units are started up and shutdown

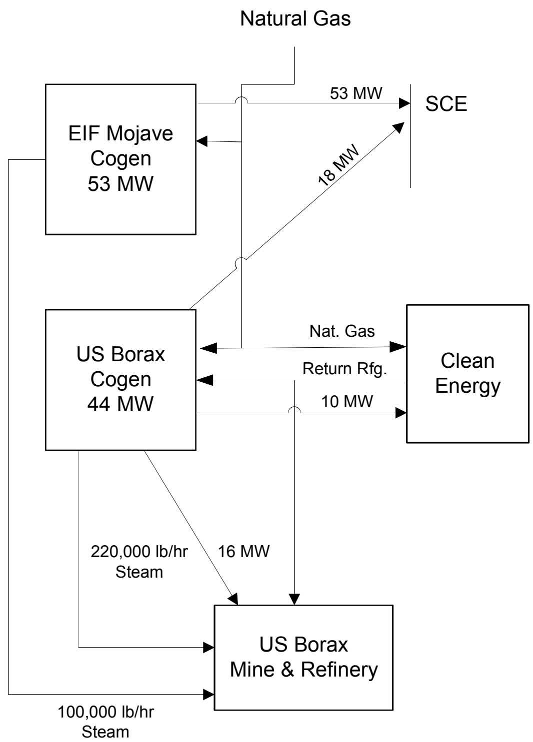
1. Minimum Demand – 60,000 lb/hr
2. Normal Minimum Demand – 120,000 lb/hr
3. Normal Demand – 320-350,000 lb/hr
4. Maximum Demand – 400,000 lb/hr

As a part of the facility steam system, US Borax has three steam boilers that are used when the steam supply from the cogeneration plants (US borax and Mojave Cogeneration) is inadequate. There are three boilers with the following operating ranges

1. Boiler #1 – 45-120,000 lbs/hr
2. Boiler #2 – 30-100,000 lbs/hr
3. Boiler #3 – 20-80,000 lbs/hr

The following illustrates the relationship between all of the facilities.

US Borax and Neighboring Energy Flows



PERMITTING CONSIDERATIONS

In proceeding with the project there are several notable permitting/licensing considerations that come into play that affect the project design and/or schedule.

California Energy Commission

The California Energy Commission (CEC) has jurisdiction for permitting thermal energy power generation projects that create more 50 MW of new generation. By limiting the output of the repowered two unit cogeneration plant to less than a 50 MW increase over the single cogeneration unit owned by Rio Tinto, it is a reasonable expectation that the project could proceed with local permitting. This criterion places an upper limit of 94 MW on the repowered cogeneration plant.

California Independent System Operator

The project will result in replacing the three existing generators at the US Borax and Mojave Cogeneration plants (two W251 gas turbines and one steam turbine) with two gas turbine generators. With the reduction in number of generators, the total rotating mass and system inertia will likely also be reduced. In addition, there will be a change in the number of generators operated by Rio Tinto (from one to two).

As a result it is reasonable to expect that an interconnect application will be required to be filed with the California Independent System Operator (CAISO). Since the net generation is not increasing and the point of interconnection remains the same, most likely no system reinforcements will be required. However they will likely still be required for the project to proceed through CAISO's study process which would also involve the interconnecting utility, Southern California Edison.

Eastern Kern Air Pollution Control District

The project is located within the jurisdiction of the Eastern Kern Air Pollution Control District (EKAPCD). The District is currently designated as an attainment area. The new units will be expected to meet Best Available Control Technology (BACT) requirements. For a base loaded plant, this typically means:

- NOx 2 ppm
- CO 4 ppm
- VOC 4 ppm
- NH_3 5 ppm

Typically for particulates, the use of pipeline quality natural gas is BACT for a gas turbine power plant. In this case EKAPCD has a limit of 0.1 grains/scf (total) for particulates. In addition they require 15 minute averaging with a 3 hour rolling average.

SB1368 Emissions Performance Standard

California Senate Bill 1368 established an emissions performance standard for power plants in California. It applies for projects operating in excess of 4,000 hours per year, e.g., baseload applications, and requires that CO_2 emissions be limited to less than 1,100 lbs/MWh. For cogeneration applications, 50% credit is also given for the net thermal energy exported assuming a perfect heat rate, e.g., 3.413 MMBtu/MWh.

US Environmental Protection Agency

For projects that create a new source of significant emissions, a Prevention of Significant Deterioration (PSD) permit is required from the Environmental Protection Agency (EPA). The Rio Tinto staff believes that PSD permitting will be required (we concur). These permits can be a lengthy undertaking of 18-24 months.

GAS TURBINE CONSIDERATIONS

The original study was centered on the use of a LM6000 PD gas turbine. This gas turbine is one of two dry low NOx (DLN) version of General Electric's family of LM6000 aero-derivative gas turbines. The LM6000 offers the advantages of being in wide use, and as is typical of aero-derivatives, easy change-out of the engine core during maintenance outages.

The mix of fuel gases at the U.S. Borax facility is potentially a troublesome fuel for gas turbines. The variable gas composition and the rapidity of change in its makeup could cause operational or emissions problems. The LM6000 PD and the newer LM6000 PF[1] (also a DLN engine), because of their dry low NOx designs, are not engines as well suited to burn a mix of fuel gases as other gas turbine models. In addition these dry low NOx engines have limited turndown, typically being guaranteed for NOx emissions compliance within the range of 65-100% of load. For this reason, the following additional engines were considered for the study:

- General Electric LM6000 PC
- Rolls Royce Trent DLN
- Siemens SGT-800
- Solar Titan 250-T30000S

The LM6000 PC utilizes water injection into the combustor section for NOx control. As a result it is less sensitive than the PD and PF versions to fuel quality. The PC also offers greater turndown typically being guaranteed down to 50% load and operating experience to 10 – 15% load.. The PC is also a lower cost engine that the PD. However this comes at the cost of significantly greater water use. The PC, PD, and PF versions all have a SPRINT option that adds water injection into the compressor section to cool the compressed air and increase mass flow resulting in increased output but with lower heat rate. Since the additional electrical generation is not needed, the SPRINT option was not considered for the final configuration.

The Rolls Royce Trent, like the LM6000, is also an aeroderivative combustion turbine. Only the dry low NOx combustor version was considered because the water injected version is more powerful, and would have produced more than 94 MW net to the grid.

The Siemens SGT-800 is an industrial gas turbine of comparable size to the LM6000. While not an aeroderivative turbine, it was included in the study because of the dry low NOx engines, it was considered to be the least sensitive to fuel supply variation

The Solar Titan 250 – T3000S is a small industrial turbine which utilizes dry low NOx technology with a net electrical output of approximately 19,200 KW. These engines were not considered acceptable due to the high capital cost associated with the three units needed to meet the electrical output along with their relatively high net heat rate.

1 The PF is an improved version of the PD with a revised combustion system design. The PF is just beginning to be deployed.

The results of the combustion turbine comparison at the annual average temperature of 59F are summarized in the following table:

		2x0 LM6000				**2x0 Rolls Royce**	**2x0 Siemens**	**3x0 Solar**
PLANT PERFORMANCE SUMMARY - ESTIMATED		PC	PC SPRINT	PD	PD SPRINT	Trent 60D Dry Low NOx	SGT-800 Dry Low NOx	Titan 250-T30000S
1	GAS TURBINE GROSS OUTPUT, KW/UNIT	39,003	45,257	38,076	42,260	46,543	42,267	19,568
2	NUMBER OF GAS TURBINES	2	2	2	2	2	2	3
3	TOTAL GROSS OUTPUT	78,006	90,514	76,152	84,520	93,085	84,533	58,705
4	PLANT AUXILIARY LOSSES, KW	1,378	1,476	1,258	1,366	1,529	1,448	1,196
5	PLANT NET OUTPUT, KW	76,628	89,038	74,894	83,154	91,556	83,085	57,509
6	NET PLANT HEAT RATE, BTU/KWH (HHV)	11,338	10,649	10,744	10,455	9,983	10,451	12,452
7	NET PLANT HEAT RATE, BTU/KWH (LHV)	10,228	9,607	9,692	9,432	9,006	9,428	11,233
8	GAS TURBINE FUEL INPUT/UNIT, MMBTU/HR (HHV)	378.66	434.10	352.83	389.48	429.02	433.60	194.11
9	DUCT BURNER FUEL INPUT/UNIT, MMBTU/HR (HHV)	55.19	39.39	48.99	44.67	27.40	0.00	44.28
10	TOTAL PLANT FUEL INPUT, MMBTU/HR (HHV)	867.70	946.97	803.64	868.29	912.84	867.20	715.18
WATER CONSUMPTION SUMMARY - ESTIMATED								
11	NOx/SPRINT WATER INJECTION, GPM	79.66	114.42	0.00	34.24	0.00	0.00	0.00
12	STEAM CYCLE MAKEUP, GPM	28.90	28.90	28.90	28.90	20.40	29.96	28.90
13	TOTAL, GPM	108.56	143.32	28.90	63.14	20.40	29.96	28.90
TOTAL EMISSIONS - ESTIMATED								
14	NOx (LBS/HR)	7.05	8.02	6.56	7.22	7.88	7.89	3.38
15	CO (LBS/HR)	5.20	3.58	4.05	4.45	8.44	4.81	3.42
16	VOC (LBS/HR)	4.54	3.39	14.89	16.16	4.08	3.30	20.45
17	PM10 (LBS/HR)	3.00	3.00	3.00	3.00	3.00	3.00	3.00
18	CO2 (LBS/HR)	102,050	111,373	94,515	102,120	107,358	101,992	84,112

		2x0 LM6000				2x0 Rolls Royce	2x0 Siemens	3x0 Solar
	SB1368 - ESTIMATED							
20	Process Steam (Btu/sec)	117,338	117,331	117,351	117,359	117,346	121,649	117,335
21	Makeup and Process Return (Btu/sec)	13,808	13,807	13,809	13,810	13,984	14,315	13,808
22	Net Energy Out (Btu/sec)	103,530	103,524	103,542	103,549	103,362	107,334	103,527
23	Net Energy Out (MW)	109.23	109.22	109.24	109.25	109.05	113.24	109.23
24	50% Reduction	55	55	55	55	55	57	55
25	Total MW	131	144	130	138	146	140	112
26	CO2 (LBS/MW-HR) (GTG + COGEN)	778	775	730	741	735	730	750

Assumptions/Notes:
1) Ambient temperature of 59° F
2) Relative humidity of 30%
3) Site Elevation of 2,400'
4) No inlet air cooling (59° F ambient)
5) No gas compression (gas supply at 700 psig)
6) Natural Gas Fuel (87% CH_4, 8.5% C_2H_6, 3.5% N_2)
7) Duct firing added to produce 175 kpph steam per turbine
8) Even without duct firing, 2x0 SGT-800 produces 362.9 kpph of steam, compared to 350 kpph for all other turbines with some firing.
9) Saturated steam output at 150 psig, maximum 10° F superheat
10) PM10 values are estimated and depends on site conditions and fuel gas analysis
11) Feedwater comes from common facility D/A at 232° F and 7 psig.

The study results led us to conclude that the Trent and SGT-800 were unsuited for the application. The Trent generated more power than the LM6000 PC and required less duct firing. The SGT-800 was well suited, but required no duct firing at all. The disadvantage with these engines in requiring less or no duct firing was that it took away an additional means to quickly deal with steam flow transients by quickly turning on or off the duct burners. These conclusions led us to consider smaller engines that would generate fewer MW and require increased duct firing. Rolls suggested the latest version of the RB211 and Siemens suggested the SGT-600 (the SGT-700 was deemed by Siemens to not be suitable given the fuel mix).

Discussions with General Electric about the available LM6000 models for this application indicate that the LM6000 PF is preferable to the LM6000 PD for a dry low NOx solution, because of a more stable combustion system, ability to handle fuel composition variations, and load following capability. With the fuel data that is currently available, GE believes the LM6000 PF to be suitable for the application. However, more fuel data will be required before GE could offer an emissions and performance guarantee on the LM6000 PF model. The turbines must also be equipped with gas chromatographs or calorimeters to constantly monitor the fuel gas quality and adjust combustion parameters as needed.

The GE LM6000 PC model can operate more easily with the fuel gas variations and over a greater operating range. The LM6000 PC has the added virtue of lower capital cost ($1,000,000 per engine) than the LM 6000 PF. This lower capital cost must be weighed against the need for water demineralization equipment and the operational cost for the water injected into the LM6000 PC combustors. Because of the lower capital cost,its more forgiving operational characteristics and that the use of the LM6000 PC will still reduce US Borax's water use, it is POWER's recommendation that the GE LM6000 PC gas turbine generator be selected as the preferred engine for initial development of the U.S. Borax New Cogeneration Facility.

All the engines considered in this study, including the recommended GE LM 6000 PC configuration, meet both the Eastern Kern Air Pollution District BACT emissions compliance requirements and the California Senate Bill 1368 CO_2 emissions standard.

Prior to making a final engine selection, these other options may still warrant consideration, particularly since they could result in less water usage. However as the focus of the study was to confirm whether repowering was viable, the remaining study work focused on the LM6000 PC as it established an upper bound on engine size.

The following additional heat and mass diagrams for the proposed configuration of two GE LM6000 PCs with duct fired HRSGs are contained in Appendix I.

1. Minimum load with emissions compliance atannual average temperature
2. Minimum load with emissions compliance at the summer average high temperature
3. Full load at the annual average temperature
4. Full load at the summer average high temperature
5. Full load at the annual average temperature, one unit out of service (OOS) with max duct firing*.
6. Full load at the summer average high temperature, one unit OOS with max duct firing*

* Maximum duct firing capability has been selected to produce 250,000 pph of process steam from one HRSG. This capability is within normal HRSG design parameters and will allow transition between one and two gas turbine generators in and out of service as process loads dictate.

LM6000 Heat Balance Summary:

Case	Description	Net Power – MW	Net Heat Rate (LLV) BTU/Kwh	Steam Flow – Lbs/hr
1	Min. load at annual average temp	23.29	9,982	82,830
2	Min. load at summer average high temp	19.55	10,561	80,430
3	Full load at annual average temp	84.76	9,766	350,000
4	Full load at summer average high temp	71.51	10,493	350,000
5	Full load at annual average temp (OOS)	42.44	11,386	250,000
6	Full load at summer average high temp (OOS)	35.62	12,420	250,000

REPOWERING US BORAX'S COGENERATION FACILITY

In repowering the cogeneration plant to replace the combined output of the existing Rio Tinto cogeneration plant and the Mojave Cogeneration plant, three distinct scopes of work will be required:

1. Build a new two unit cogeneration plant.
2. Interconnect the new cogeneration plant to the existing facility electrical, water, and fuel gas systems

3. Build new facilities to replace those services currently supplied by Mojave Cogeneration that will still be required in the future, namely demineralized water for water injection into the LM6000s for NOx control.

Work Scope 1 – Build a new two unit cogeneration facility

A new two unit cogeneration facility will be built directly west of the existing U.S. Borax Cogeneration facility and the Mojave Cogeneration Plant. A preliminary Site Plan for this new facility is shown in Appendix D. The new facility will occupy an area approximately 500 feet by 500 feet. The new facility will consist of two GE LM6000 PC combustion turbines that will utilize evaporative coolers to mitigate the loss of power on hot days.

Associated with each gas turbine will be a conventional horizontal flow heat recovery steam generator (HRSG). In addition to accommodating the tube bundles necessary to create steam, each HRSG will also incorporate various elements needed to reduce the level of emissions including a) a CO catalyst, b) aqueous ammonia storage tank, an aqueous ammonia forwarding pump and ammonia injection grids.

A new Continuous Emission Monitoring (CEM) system will be installed adjacent to each of the new turbine exhaust stacks to monitor and record the emission of the new combustion turbines. These new CEMs units will be packaged skid mounted systems and sufficient storage racks will be provided for the required calibration gas cylinders.

A pipe support system will be provided for the new feed water and steam piping to the existing plant interconnection points.

A 13.8/ 34.5 kV generator step up (GSU) transformer will be required for each new combustion turbine generator. One new GSU will be procured and installed and the existing GSU from the existing Rio Tinto Cogeneration plant will be relocated to serve the second combustion turbine generator[2].

A total of four auxiliary transformers will be installed for the new cogeneration plant. Each combustion turbine generator will be provided with a new 13.8/ 4 kV and a 13.8 kV/ 480 V auxiliary transformer. A skid mounted Power Distribution Center (PDC) will be provided to interconnect the auxiliary transformers with the required cogeneration plant loads. A black start generator will be installed that can be aligned to either unit through switching in the PDC.

The existing facility fire water system will be extended to serve the new site. We have assumed that additional fire pumps or tankage will not be required. In addition, redundant air compressors, service air receiver, and instrument air receiver will also be included.

All areas of the cogeneration plant site will be surfaced with concrete consistent with Rio Tinto standards. In addition, security fencing will be installed as well as outdoor lighting with full cutoffs to limit stray light.

[2] This sequence will allow the new Unit 1 to be built and commissioned so it can operate in parallel with Mojave Cogeneration while the existing US Borax cogeneration plant is shut down and the new Unit 2 is constructed.

Work Scope 2 – Interconnect the new cogeneration facility to the existing facility electrical, water, and fuel gas systems

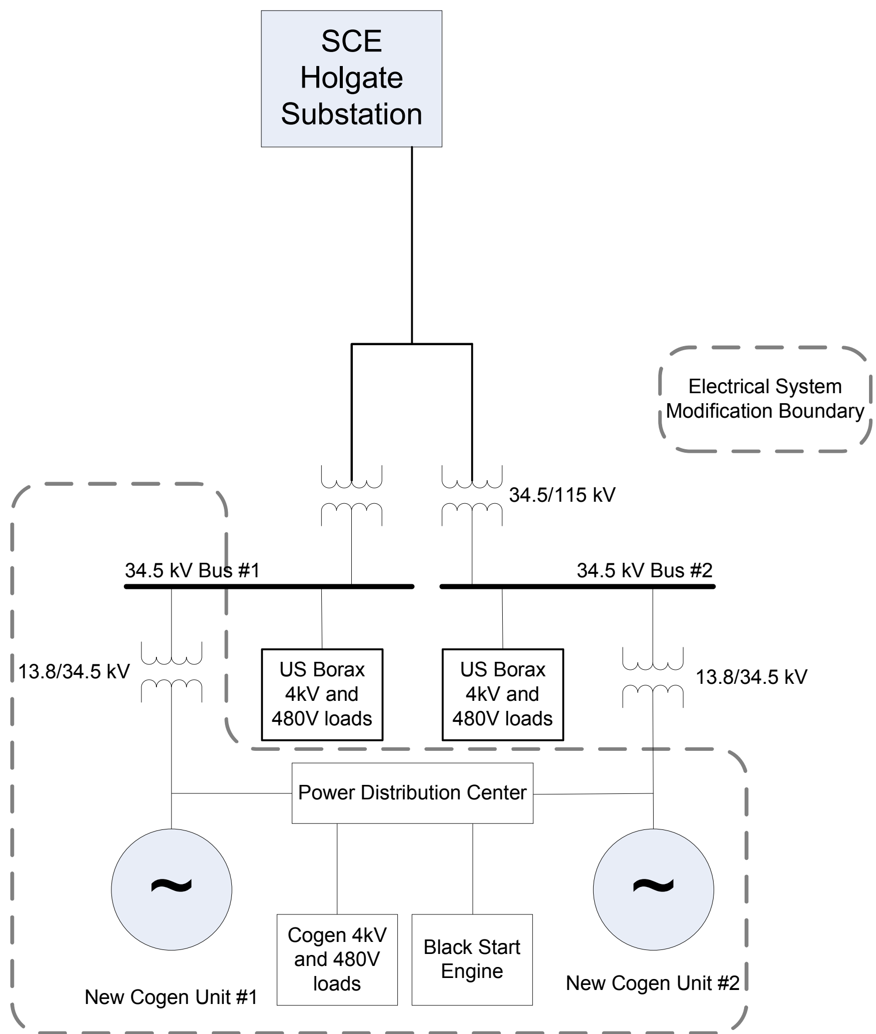
The repowered cogeneration plant must interconnect to the existing facility electrical, water, and fuel systems.

The Unit 1 gas turbine generator would feed a new 13.8/34.5 kV GSU transformer. This transformer would connect through a new underground duct bank to a new section of 34.5 kV switchgear that would be added onto the existing 34.5 kV Bus #1. Extending Bus #1 would also entail lengthening the metal building in which it resides.

The Unit 2 gas turbine generator would connect to the 34.5 kV Bus #1 as the current US Borax cogeneration unit currently does. By doing so, this would allow the new Unit 1 to be placed in service and operate in parallel with Mojave Cogeneration while Unit 2 is completed. This sequence also offers the potential opportunity to then re-use the existing 13.8/34.5 kV GSU transformer[3]. This would also require that the underground duct bank being extended from the current US Borax cogeneration site to the new site.

[3] This transformer was replaced a few years ago and is thus relatively new. As long as the transformer ratings are consistent with the new gas turbine and system requirements, it offers the opportunity to recycle part of the existing plant.

AS MODIFIED ELECTRICAL SCHEMATIC



Data and communication links would be installed to allow the facility DCS and control room to interact with the new units.

The steam and feed water headers must be extended to the new site. As part of this work, we would need to establish new tie-in locations either during a facility outage or by using hot taps. These tie-in points would also include a pair of isolation valves in series so that the header could remain in operation while construction work continues on the other side of the closed isolation valves. As these valves would be infrequently operated, manual valves could be used.

Work Scope 3 – Build new facilities to replace those services currently supplied by Mojave Cogeneration

Demineralized water is currently provided by Mojave Cogeneration. As the new LM6000 PC combustion turbines will require approximately 109 gallons per minute of demineralized water for injection into to the combustion sections for NOx emission compliance, a new demineralized water plant will be installed as part of the project.

Either the facility's potable water system or feed water system could be used as a source of water. Given these sources, a conventional mixed bed demineralizer could be used. The mixed beds could be regenerated off-site, or an acid-caustic-neutralization system could be utilized for on-site regeneration.

The existing demineralized water storage tank is of adequate size for the new NOx water injection systems. If needed, the tank could be relocated

COST ESTIMATE

An order of magnitude cost estimate for the engineering, procurement, and construction of the New Cogeneration Facility Project was created to provide a guide for continued project development. This cost estimate is presented in Appendix H. Preliminary equipment specifications were written and issued to selected suppliers for budgetary equipment quotations. The specifications and responding equipment suppliers are:

1. Combustion Gas Turbine Generator
    a. General Electric
    b. Rolls Royce
    c. Siemens
2. Heat Recovery Steam Generators
    a. Deltak
    b. Express Integrated Technologies
    c. Nooter/Ericksen
    d. Rentech Boiler Systems
    e. Victory Energy
3. Plant Fuel Gas Filter and Heater System
    a. Fluid Engineering
    b. Integrated Flow Solutions

The costs of other equipment required for the project were factored from previous projects.

The engineering, procurement, and construction cost estimate does not include the following items:

1. Project development costs
2. Permitting costs including emissions offsets
3. CAISO interconnect study and reinforcement costs

4. Building permit fees
5. Financing costs
6. Builder's All Risk Insurance
7. Spare parts, other than those required for commissioning
8. Commissioning fuel and water costs
9. Operator expenses
10. Escalation
11. Schedule acceleration costs

The following assumptions were made concerning the design of the project and existing equipment and systems:

1. The existing boiler feedwater pumps at the refinery boiler house will be adequate to furnish boiler feedwater to the new HRSGs. Therefore, new boiler feedwater pumps have not been included.
2. A new fuel gas metering station will be required and is included in the estimate.
3. The existing refinery boiler house programmable logic control system has adequate capacity to act as the balance of plant control system for the new cogeneration power plant. Re-programming costs for this control system are included in the estimate.
4. The existing generator step up transformer for the refinery cogeneration plant may be reused at the new cogeneration plant for one of the new LM6000 combustion gas turbine generators. Therefore, only one new generator step up transformers is included in the estimate.
5. Black start capability is desired; therefore, a diesel engine generator and required electrical gear for black start is included in the estimate.
6. Foundation piles will not be necessary; therefore, the estimate is based upon spread footing type foundations.
7. Costs are estimated in today's dollars.
8. Heavy equipment may be delivered to the refinery site by rail.
9. The project is constructed during normal market conditions. Construction during times of high labor demand such as large renewable projects or a re-bound in the gas turbine construction market could escalate labor prices and require additional "attraction" costs to bring workers to the project.

Based on the foregoing scope and assumptions, we developed a +/- 10% EPC cost estimate of $101,837,000.

SCHEDULE

There are two main variables that determine the length of the New Cogeneration Facility Project schedule:

1. Permitting of the Project. As discussed in the body of this report, the project will require a Prevention of Significant Deterioration (PSD) permit. Expected time to obtain this permit is 18 to 24 months. The following schedule is based on a total length of permitting time of 24 months to obtain this permit, including the required modeling study that is a requirement of the permit application.

2. Placement of Purchase Orders for the Main Plant Equipment. To begin field construction upon issuance of the permit Authority to Construct will require orders to be placed for the main plant equipment (gas turbine generators and heat recovery steam generators) in advance. The attached schedule is based upon engineering and equipment purchase to allow the earliest construction start date. This schedule follows a design-bid-build model. If early placement of equipment orders is not practical or desired, then the project completion time will be considerably lengthened. If equipment

purchase commitment is desired to occur after obtaining the air permits, an engineering, procurement, and construction (EPC) project execution model may be beneficial. With EPC, the subsequent project schedule time would be minimized and all project completion and performance guarantees would reside with one entity.

The project schedule for the New Cogeneration Facility is presented as Appendix G.

SOLAR THERMAL AS AN OPTION

With a project location in Mojave, a need for steam, and a large flat area adjacent to the cogeneration plant, one of the options we considered for the project is solar thermal. Such a system would offer a steam source with quick turndown and no emissions. The use of such a system could displace duct firing or operation of one unit during daytime hours.

There are a number of solar thermal systems that are being offered. For the US Borax application we would recommend one of the systems that is all water-based. Other systems that use a heat transfer fluid (oil or molten salt) would introduce an additional complication whereas the closed water systems are directly compatible with the project needs and don't have the issues of flammability or toxicity.

Of the solely water based systems, there are two that could be applicable to US Borax:

- Areva Solar uses a Compact Linear Fresnel Reflector (CLFR) that directly heats water in long horizontal receivers to generate steam. Their Kimberlina demonstration plant is located just north of Bakersfield and has been in operation for a few years.

- eSolar uses heliostats and a power tower in a modular array (each module generates 2.5 MWe) to generate superheated steam. Their demonstration plant is located in Lancaster and has been in operation for two years.

Of the two, we believe the Areva Solar system may be a better fit as it can be tailored to generate low pressure steam consistent with the refinery's needs. The eSolar design is designed to generate superheated steam for power production.

In discussions with Areva, they estimate that a plant generating 100,000 lbs/hr would require 5-6 of their receivers (the Kimberlina plant uses 4 receivers) and require a space of approximately 600 feet x 1500 feet with the long axis in the north-south direction. The system would need to operate at ~300 psig to ensure flow stability within the receivers necessitating the addition of feedwater booster pumps at the cogeneration plant and pressure reducing station to supply process steam. The feedwater pumps could be powered from the Power Distribution Center that is planned for the cogeneration plant. The estimated installed cost of such a system is $18 - $23 million (exclusive of site, permitting, and interconnection costs) with equipment delivery available in 6 months. The system could be scaled up or down to provide more or less steam. This would have some affect on pricing as there is an economy of scale that comes into play.

CONCLUSION

The results of this study indicate that a new cogeneration plant consisting of two General Electric LM 6000 PC combustion turbines with duct fired HRSGs is the best choice to satisfy the following two operating parameters.

- Reliable steam generation with the ability to change steam loads very rapidly due to the heavily duct fired HRSG configuration. This is especially critical when the steam load exceeds the electrical load.
- Ability to accept a varying fuel supply due to the water injection system utilized into the combustors.

The proposed plant will not require permitting though the California Energy Commission since the output of the new two unit cogeneration plant is less than a 50 MW increase over the maximum electrical output of the existing Rio Tinto cogeneration plant. However due to the base load operation of the new plant and the resulting annual emissions, it is highly likely that the new plant will be required to obtain an emission discharge permit from the US EPA. A conservative estimate for obtaining a permit from the EPA is 18 to 24 months. This results in an overall plant completion date of December 2013 assuming an immediate start and normal construction duration.

The estimated cost to complete this project is $101,837,000. This does not include the owner soft costs such as permitting, interconnection fees, emissions offsets and financing costs.

Appendix D
GE LM6000 CGS Performance Guarantee

GE ENERGY

GUARANTEE
PROJECT: BLACK HILLS WYOMING
LOCATION: WY, USA

KW AT GEN TERMS	38820
BTU/KW-HR, LHV	8451
(KJ/KW-HR, LHV)	8916

EMISSIONS ARE VALID FOR T2 WITHIN 0F-120F AND A GTG LOAD DOWN TO 50% AS DEFINED IN STEADY STATE CONDITIONS

Adesoji Dairo
Performance Engineer Date: 06/30/11

NOX:25 PPMVD AT 15% O2 (51 mg/Nm3)
CO:70 PPMVD AT 15% O2 (88 mg/Nm3)
VOC: 8.4 PPMVD AT 15% O2 (6 mg/Nm3)
PM10:4 LB/HR (2 kg/hr)

NOT VALID WITHOUT SIGNATURE

VALID UNTIL 09/28/11

BASIS OF GUARANTEE:BASE LOAD, GAS FUEL NOZZLE SYSTEM
NO BLEED OR EXTRACTED POWER

ENGINE:	(1) GE LM6000PF-SPRINT-25 DLE GAS TURBINE
FUEL:	21000Btu/lb / (48846 kJ/kg) LHV, GAS FUEL (#900-3029)
FUEL SPEC:	MID-TD-0000-1 LATEST REVISION
FUEL TEMP:	SITE FUEL TEMPERATURE OF 76.9°F(25.0°C)
GENERATOR:	BDAX 7-290ERJT
GENERATOR OUTPUT	13.8kV, 60 Hz
POWER FACTOR:	□1
AMBIENT TEMP:	95.0°F / (35.0°C)
AMBIENT RH:	20.0%
INLET CONDITIONING:	CHILL TO 47.0°F / (8.3°C) AT 95.0% RH
ALTITUDE:	5950.0ft / (1813.6m)
INLET FILTER LOSS:	< 5.00 inH_2O / (127.0 mmH_2O)
EXHAUST LOSS:	< 12.00 inH_2O / (304.8 mmH_2O)
NO_x CONTROL:	DLE
ENGINE CONDITION:	NEW AND CLEAN <200 SITE FIRED HOURS
FIELD TEST METHODS	
PERFORMANCE:	GE ENERGY SGTGPTM
NOX:	EPA METHOD 20
CO:	EPA METHOD 10
VOC:	EPA METHOD 25A/18
PM10:	EPA METHOD 5 / 202

BASIS OF GUARANTEE IS NOT FOR DESIGN, REFER TO PROJECT DRAWINGS FOR DESIGN REQUIREMENTS. SI VALUES ARE FOR REFERENCE PURPOSES ONLY.

THIS GUARANTEE SUPERSEDES ANY PREVIOUS GUARANTEES PRESENTED

Conditions for VOC Emissions Guarantee

1. Fuel must meet GE specification MID-TD-000-01.
2. The timing of test to coincide with lowest site ambient VOCs levels.
3. Gas turbine must run for a minimum of 300 total fired hours at base load prior to testing.
4. Gas turbine inlet and exhaust system must be free of any dirt, sand, mud, rust, oil or any other contaminates.
5. Re-testing (at purchaser's expense) must be allowed, if required.
6. GE receives a copy of the final test results.
7. A compressor wash prior to testing is highly recommended.

Conditions for PM10 Emissions Guarantee

1. Fuel must meet GE specification MID-TD-000-01.
2. The timing of test to coincide with lowest site ambient particulate levels.
3. Gas turbine must run for a minimum of 300 total fired hours at base load prior to testing.
4. Combustion turbine must be run for a minimum of 300 total fired hours prior to any particulate testing; combustion turbine must be operating a minimum of 3 - 4 hours at base load prior to PM / PM10 test run.
5. Gas turbine inlet and exhaust system must be free of any dirt, sand, mud, rust, oil or any other contaminates.
6. Sampling probe internal surfaces must be made of chemically inert and non- catalytic material such as quartz.
7. The filter material shall be quartz.
8. Probe wash shall be high purity acetone per EPA Method 5.
9. Re-testing (at purchaser's expense) must be allowed, if required.
10. GE receives a copy of the final test results.
11. A compressor wash prior to testing is highly recommended.
12. The area around the turbine is to be treated (for example, sprayed down with water) to minimize airborne dust.

Conditions for Steady State Guarantee

1.	Power Output (electrical)	±10.0% / Min
2.	T2 Compressor Inlet air temperature	± 2.5°F / 5.0 Min
3.	Heat Value - gaseous fuel per unit volume	±0.25% / Min
4.	Pressure - gaseous fuel as supplied to engine	± 10 PSIG / 5.0 Min

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

Performance By: **Adesoji Dairo** Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **12:59:23 PM**
Version: **3.9.0**

Case #	**100**
Ambient Conditions	
Dry Bulb, °F	95.0
Wet Bulb, °F	63.9
RH, %	20.0
Altitude, ft	5950.0
Ambient Pressure, psia	11.799
Engine Inlet	
Comp Inlet Temp, °F	47.0
RH, %	95.0
Conditioning	CHILL
Tons or kBtu/hr	885
Pressure Losses	
Inlet Loss, inH20	5.00
Volute Loss, inH20	4.00
Exhaust Loss, inH20	12.00
Partload %	**100**
kW, Gen Terms	**38820**
Est. Btu/kW-hr, LHV	**8282**
Guar. Btu/kW-hr, LHV	**8451**
Fuel Flow	
MMBtu/hr, LHV	321.5
lb/hr	15310
NOx Control	**DLE**
SPRINT	**LPC**
lb/hr	7069
Control Parameters	
HP Speed, RPM	10354
LP Speed, RPM	3600
PS3 - CDP, psia	369.5
T25 - HPC Inlet Temp, °F	193.0
T3CRF - CDT, °F	945
T48IN, °R	2046
T48IN, °F	1587
Exhaust Parameters	
Temperature, °F	856.3
lb/sec	235.2
lb/hr	846706
Energy, Btu/s- Ref 0 °R	79113
Energy, Btu/s- Ref T2 °F	49517
Cp, Btu/lb-R	0.2733
Emissions (ESTIMATED, NOT FOR GUARANTEE)	
NOx ppmvd Ref 15% O2	25
NOx as NO2, lb/hr	32
CO ppmvd Ref 15% O2	25
CO, lb/hr	19.63
CO2, lb/hr	41943.27
HC ppmvd Ref 15% O2	15
HC, lb/hr	6.73
SOX as SO2, lb/hr	0.00

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo** Project Info: **Black Hills Wyoming**

Engine:	**LM6000 PF-SPRINT-25**		
Deck Info:	**G0125P - 8i6.scp**	Date:	**06/30/2011**
Generator:	**BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**	Time:	**12:59:23 PM**
Fuel:	**Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**	Version:	**3.9.0**

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

Case #	**100**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	1.2435
N2	72.9173
O2	15.3205
CO2	4.9537
H20	5.5593
SO2	0.0000
CO	0.0023
HC	0.0008
NOX	0.0026

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	0.9650
N2	80.6950
O2	14.8437
CO2	3.4896
H20	0.0000
SO2	0.0000
CO	0.0026
HC	0.0015
NOX	0.0026

Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	0.8808
N2	73.6490
O2	13.5476
CO2	3.1849
H20	8.7317
SO2	0.0000
CO	0.0023
HC	0.0014
NOX	0.0023

Aero Energy Fuel Number **900-3029 (Black Hills Wyoming)**

	Volume %	Weight %
Hydrogen	0.0000	0.0000
Methane	95.5018	90.7897
Ethane	3.0123	5.3675
Ethylene	0.0000	0.0000
Propane	0.4638	1.2119
Propylene	0.0000	0.0000
Butane	0.1190	0.4099
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0240	0.1026
Cyclopentane	0.0000	0.0000
Hexane	0.0135	0.0689
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.6458	1.6843
Nitrogen	0.2200	0.3652
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

Btu/lb, LHV	21000
Btu/scf, LHV	936.2
Btu/scf, HHV	1037.6
Btu/lb, HHV	23274
Fuel Temp, °F	76.9
NOx Scalar	1.011
Specific Gravity	0.58

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo** Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **1:05:44 PM**
Version: **3.9.0**

Case #	**100**
Ambient Conditions	
Dry Bulb, °C	35.0
Wet Bulb, °C	17.7
RH, %	20.0
Altitude, m	1813.6
Ambient Pressure, kPa	81.353
Engine Inlet	
Comp Inlet Temp, °C	8.3
RH, %	95.0
Conditioning	CHILL
Tons or kBtu/hr	885
Pressure Losses	
Inlet Loss, mmH2O	127.00
Volute Loss, mmH2O	101.60
Exhaust Loss, mmH2O	304.80
Partload %	**100**
kW, Gen Terms	**38820**
Est. kJ/kWh, LHV	**8738**
Guar. kJ/kWh, LHV	**8916**
Fuel Flow	
GJ/hr, LHV	339.2
kg/hr	6944
NOx Control	**DLE**
SPRINT	**LPC**
kg/hr	3206
Control Parameters	
HP Speed, RPM	10354
LP Speed, RPM	3600
PS3 - CDP, kPa	2547.7
T25 - HPC Inlet Temp, °C	89.4
T3CRF - CDT, °C	507
T48IN, °K	1137
T48IN, °C	864
Exhaust Parameters	
Temperature, °C	457.9
kg/sec	106.7
kg/hr	384063
Energy, KJ/s- Ref 0 °K	83469
Energy, KJ/s- Ref T2 °C	52243
Kj/kg-R	1.1440
Emissions (ESTIMATED, NOT FOR GUARANTEE)	
NOx mg/Nm3 Ref 15% O2	51
NOx as NO2, kg/hr	15
CO mg/Nm3 Ref 15% O2	31
CO, kg/hr	8.90
CO2, kg/hr	19025.34
HC mg/Nm3 Ref 15% O2	11
HC, kg/hr	3.05
SOX as SO2, kg/hr	0.00

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

GE Energy

Performance By: **Adesoji Dairo** Project Info: **Black Hills Wyoming**

Engine: **LM6000 PF-SPRINT-25**
Deck Info: **G0125P - 8i6.scp**
Generator: **BDAX 7-290ERJT 60Hz, 13.8kV, 1PF (35405)**
Fuel: **Site Gas Fuel#900-3029, 21000 Btu/lb,LHV**

Date: **06/30/2011**
Time: **1:05:44 PM**
Version: **3.9.0**

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN

Case #	**100**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)	
AR	1.2435
N2	72.9173
O2	15.3205
CO2	4.9537
H20	5.5593
SO2	0.0000
CO	0.0023
HC	0.0008
NOX	0.0026

Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	0.9650
N2	80.6950
O2	14.8437
CO2	3.4896
H20	0.0000
SO2	0.0000
CO	0.0026
HC	0.0015
NOX	0.0026

Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)

AR	0.8808
N2	73.6490
O2	13.5476
CO2	3.1 849
H20	8.7317
SO2	0.0000
CO	0.0023
HC	0.0014
NOX	0.0023

Aero Energy Fuel Number **900-3029 (Black Hills Wyoming)**

	Volume %	Weight %
Hydrogen	0.0000	0.0000
Methane	95.5018	90.7897
Ethane	3.0123	5.3675
Ethylene	0.0000	0.0000
Propane	0.4638	1.2119
Propylene	0.0000	0.0000
Butane	0.1190	0.4099
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.0240	0.1026
Cyclopentane	0.0000	0.0000
Hexane	0.0135	0.0689
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.6458	1.6843
Nitrogen	0.2200	0.3652
Water Vapor	0.0000	0.0000
Oxygen	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

kJ/kg, LHV	48846
kJ/Nm3, LHV	36774.2
kJ/Nm3, HHV	40754.8
kJ/kg, HHV	54134
Fuel Temp, °C	25.0
NOx Scalar	1.011
Specific Gravity	0.58

Appendix E
October 31, 2011 Letter from CEC

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512
www.energy.ca.gov

October 31, 2011

Mr. Steve Baele
General Manager, Projects
Rio Tinto Materials
300 Falcon Street
Wilmington, CA 90744

Re: Cogeneration Plant at Rio Tinto Minerals' U.S. Borax Facility

Dear Mr. Baele:

We received your letter dated October 21, 2011 describing an upgrade to the U.S. Borax Facility at Boron. You have asked for concurrence that the new cogeneration project is not subject to CEC review or jurisdiction.

In short, you state that the current 44 megawatt facility will be retired and a new 76 megawatt facility will replace it. The net increase in generating capacity will be 32 megawatts.

We believe that the case of Department of Water and Power v. Energy Commission, 2 Cal.App.4th 206 (1991) is dispositive here, and therefore your new facility is not subject to Energy Commission jurisdiction. However, if the facts surrounding the new facility are not the same as set forth in your October 21, 2011 letter, or the actual facts differ in such a way as to make the Department of Water and Power case inapposite, the Energy Commission reserves the right to reconsider this conclusion.

Sincerely,

Terrence O'Brien

TERRENCE O'BRIEN
Deputy Director
Siting, Transmission,
and Environmental Protection Division

cc: Jeffery Ogata, Assistant Chief Counsel, Legal Office
Robert Worl, Planner III, Siting, Transmission and Environmental Protection Division
Chris Davis, Office Manager, Siting, Transmission and Environmental Protection Division